6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2017-0483; FRL-XXXX-XX-OAR]

RIN 2060-AT54

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final Rule.

SUMMARY: This action finalizes amendments to the new source performance standards (NSPS) at 40 Code of Federal Regulations (CFR) part 60, subpart OOOOa, for the oil and natural gas sector. The Environmental Protection Agency (EPA) granted reconsideration on the fugitive emissions requirements, well site pneumatic pump standards, and the requirements for certification of closed vent systems by a professional engineer. This action finalizes amendments and clarifications as a result of reconsideration of these issues. These final amendments also address other issues raised for reconsideration and make technical corrections and amendments to further clarify the rule.

DATES: This final rule is effective on [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA-HQ-OAR-2017-0483. All documents in the docket are listed on the http://www.regulations.gov web site. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through http://www.regulations.gov.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Ms. Karen Marsh, Sector Policies and Programs Division (E143-05), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-1065; fax number: (919) 541-3470; and email address: marsh.karen@epa.gov. For information about the applicability of the new source performance standard (NSPS) to a particular entity, contact Ms. Marcia Mia, Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, EPA WJC South Building (Mail Code 2227A), 1200 Pennsylvania Avenue, NW, Washington DC 20460; telephone number: (202) 564-7042; and email address: mia.marcia@epa.gov.

SUPPLEMENTARY INFORMATION:

Preamble Acronyms and Abbreviations. A number of acronyms and abbreviations are used in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined:

AMEL	Alternative Means of Emission Limitation
ANSI	American National Standards Institute
API	American Petroleum Institute
AVO	Auditory, Visual, and Olfactory
AWP	Alternative Work Practice
BMP	Best Management Practice
boe	Barrels of Oil Equivalent
BSER	Best System of Emissions Reduction
CAA	Clean Air Act

CAPP	Canadian Association of Petroleum Producers
CBI	Confidential Business Information
CEDRI	Compliance and Emissions Data Reporting Interface
CFR	Code of Federal Regulations
CO2 Eq.	Carbon dioxide equivalent
CPI	Consumer Price Indices
CVS	Closed Vent System
DOE	Department of Energy
EAV	Equivalent Annualized Value
EPA	Environmental Protection Agency
FEAST	Fugitive Emissions Abatement Simulation Toolkit
GHG	Greenhouse Gases
GHGI	Greenhouse Gas Inventory
GHGRP	Greenhouse Gas Reporting Program
HAP	Hazardous Air Pollutant
ITRC	Interstate Technology and Regulatory Council
LDAR	Leak Detection and Repair
METEC	Methane Emissions Technology Evaluation Center
NEMS	National Energy Modeling System
NSPS	New Source Performance Standards
NSR/PSD	New Source Review/Prevention of Significant Deterioration
NSSN	National Standards System Network
NTTAA	National Technology Transfer and Advancement Act
OGI	Optical Gas Imaging
OMB	Office of Management and Budget
PE	Professional Engineer
PRA	Paperwork Reduction Act
PRD	Pressure Relief Device
PRV	Pressure Relief Valve
PTE	Potential to Emit
PV	Present Value
REC	Reduced Emissions Completion
RFA	Regulatory Flexibility Act
RIA	Regulatory Impact Analysis
RTC	Responses to Comments
SOCMI	Synthetic Organic Chemicals Manufacturing Industry
tpy	tons per year
TSD	Technical Support Document
UIC	Underground Injection Control

UMRA Unfunded Mandates Reform Act

VOC Volatile Organic Compounds

VRU Vapor Recovery Unit

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I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

The purpose of this action is to finalize amendments to the NSPS for the oil and natural gas source category based on our reconsideration of those standards. On June 3, 2016, the EPA published a final rule titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule," at 81 FR 35824 ("2016 NSPS OOOOa"). NSPS OOOOa sets for the standards for reducing emissions of greenhouse gases (GHG), in the form of limitations on methane, and volatile organic compounds (VOC) from the oil and natural gas sources constructed, modified or reconstructed after September 15, 2015.1 Following promulgation of the final rule, the Administrator received petitions for reconsideration of several provisions of NSPS OOOOa.2 The EPA granted reconsideration on three issues: (1) applicability of the fugitive emissions requirements to low production well sites, (2) process and criteria for requesting approval of an AMEL, (3) well site pneumatic pump standards, and (4) the requirements for certification of closed vent systems by a professional engineer. On October 15, 2018, the EPA published a proposed rule title "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration," in which EPA proposed amendments to NSPS OOOOa to address those specific issues raised for reconsideration and other implementation issues and technical corrections identified after promulgation of the rule. 83 FR 52056. This action finalizes certain amendments to NSPS OOOOa.

2. Summary of the Major Provisions of this Final Rule

The EPA is finalizing amendments and clarifications related to specific issues for which reconsideration was granted: fugitive emissions requirements, well site pneumatic pump standards, the requirements for certification of closed vent systems, and the alternative means of emissions limitation provisions. The EPA is also finalizing amendments to clarify and streamline implementation of the rule. These amendments include the following provisions: well completions (location of a separator during flowback, screenouts, and coil tubing cleanouts), onshore natural gas processing plants (definition of capital expenditure and monitoring), storage vessels (applicability), and general clarifications (certifying official and recordkeeping and reporting). Lastly, in addition to the amendments addressing reconsideration and implementation issues, the EPA is finalizing technical corrections of inadvertent errors in the 2016 NSPS OOOOa.

Well completions. This final rule amends 40 CFR 60.5375a(a)(1)(iii) to require a separator in close proximity to the well (i.e., onsite or nearby) during flowback so that it can be utilized as soon as it technically feasible for the separator to function. We are also amending 40 CFR 60.5375a(a)(1)(i) to clarify the use of a production separator during the initial flowback stage, on the condition that it is also designed to accommodate flowback.

The definition of flowback at 40 CFR 60.5430a is amended in this final rule to exclude screenouts, coil tubing cleanouts, and plug drill outs, as these are functional processes that allow for flowback to begin.

Pneumatic pumps. This final rule expands the technical infeasibility provision for control of a pneumatic pump to all well sites by removing the greenfield site definition from 40 CFR 60.5430a. Additionally, this final rule allows certification of technical infeasibility to control a pneumatic pump by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the pneumatic pump such that the emissions characteristics may be determined for the feasibility of control within existing closed vent system and control device operational limitations.

Storage vessels. This final rule amends the applicability criteria for storage vessel affected facilities by clarifying how the potential for VOC emissions is calculated for one subcategory of storage vessels ("Type 1") and establishes and sets separate performance standards for a second subcategory of storage vessels ("Type 2"). The Type 2 storage vessels are manifolded together with piping such that all vapors are shared between the headspace of the storage vessels, and their emissions, which are shared and indistinguishable, are routed through a closed vent system to a process or a control device with a destruction efficiency of at least 95.0 percent for VOC emissions.

Closed vent systems (CVS). This final rule incorporates the option to demonstrate the pneumatic pump CVS is operated with no detectable emissions by either an annual inspection using EPA Method 21, monthly AVO monitoring, or optical gas imaging monitoring at the frequencies specified for fugitive monitoring. Additionally, this final rule incorporates the option for a storage vessel CVS to be monitored by either monthly AVO monitoring, or optical gas imaging monitoring at the frequencies specified for fugitive monitoring. Finally, this final rule allows certification of the CVS by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the CVS.

Fugitive emissions requirements. The EPA is finalizing several amendments to the requirements for the collection of fugitive emissions components at a well site or at a compressor station. First, this final rule requires annual monitoring of fugitive emissions for compressor stations located on the Alaska North Slope and finalizes separate initial monitoring requirements for these Alaska compressor stations. These compressor stations are required to conduct initial monitoring within 6 months or by June 30, whichever is later, for compressor stations that startup between September and March or within 90 days for compressor stations that startup between April and August. This final rule also revises the initial monitoring requirement for well sites and compressor stations not located on the Alaska North Slope by providing 90 days after startup. Additionally, the final amendments allow fugitive monitoring to stop when all major production and processing equipment is removed from a well site such that is becomes a wellhead only well site.

In addition to the amendments related to monitoring frequencies, the EPA is finalizing the specific events which constitute modification for a separate tank battery well site; revising the repair requirements to specify a first attempt at repair is required within 30 days of identifying the fugitive emissions, and final repair is required within 30 days of the first attempt at repair; amending the definition of well site to exclude third party equipment located downstream of the custody meter assembly and UIC Class I non-hazardous and UIC Class II disposal wells from the fugitive emissions requirements; and revising the requirements for the monitoring plan, recordkeeping, and reporting associated with the fugitive emissions requirements.

Alternative means of emission limitation (AMEL). This final rule amends the provisions for application of an AMEL for emerging technologies or for existing state fugitive emissions programs. Additionally, this final rule provides alternative fugitive emissions standards for well sites and compressor stations located in specific states.

Onshore natural gas processing plants. This final rule revises definition of "capital expenditure" at 40 CFR 50.5430a by replacing the equation used to determine the percent of replacement cost, "Y". Additionally, this final rule exempts components in VOC service less than 300 hours/year from monitoring and clarifies the initial compliance date for a newly affected process unit.

Sweetening units. This final rule revises the applicability of the SO2 standards on sweetening units by clarifying that any sweetening unit, regardless of location is subject to the standards.

3. Costs and Benefits

The EPA has projected the compliance cost savings, emissions changes, and forgone benefits that may result from the final reconsideration. The projected cost savings and forgone benefits are presented in the Regulatory Impact Analysis (RIA) accompanying this reconsideration. The RIA focuses on the elements of the final rule-the provisions related to fugitive emissions requirements and certification by a professional engineer- that are likely to result in quantifiable cost or emissions changes compared to a baseline that includes the 2016 NSPS OOOOa requirements.

The effects of this final reconsideration are estimated for all sources that are projected to change compliance activities under this action for the analysis years 2019 through 2025. The RIA also presents the present value (PV) and equivalent annualized value (EAV) of costs, benefits and net benefits of this action in 2016 dollars.

A summary of the key results of this final action are presented in Table 1. Table 1 presents the PV and EAV, estimated using discount rates of 7 and 3 percent, of the changes in benefits, costs, and net benefits, as well as the change in emissions under the final reconsideration. In the following tables, the EPA refers to the cost savings as the "benefits" of this proposed action and the forgone benefits as the "costs" of this proposed action. The net benefits are the benefits (cost savings) minus the costs (forgone benefits).

TABLE 1. Cost Savings, Forgone Benefits and Increase in Emissions of the Final Reconsideration Relative to the 2018 Baseline, 2019 Through 2025 (Millions 2016$)

	7%		3%	
	Present Value	Equivalent Annualized Value	Present Value	Equivalent Annualized Value
Benefits (Total Cost Savings)	$189	$33	$240	$37
Costs (Forgone Benefits)	$0	$0	$0	$0
Net Benefits1	$189	$33	$240	$37
Emissions				
Total Change				

Methane (short tons)

0

VOC

0

HAP

0

Methane (million metric tons CO2 Eq.)

0

1 Estimates may not sum due to independent rounding.

The projected cost savings and forgone benefits of this action are presented in the RIA accompanying this reconsideration. The only expected impacts on VOC, methane, and hazardous air pollutant (HAP) emissions from this reconsideration are likely to be from reducing the monitoring frequency for affected compressor stations on the Alaskan North Slope. However, EPA does not have information that enables the projection of emissions changes that may result from reducing the frequency of fugitive emision monitoring at the Alaskan sites. All other finalized changes to the NSPS OOOOa are not expected to lead to changes in emissions compared to the 2018 NSPS OOOOa baseline (Table 1). As there are not quantified emissions impacts from the finalized option, the finalized changes to NSPS OOOOa are not expected to result in monetized disbenefits (Table 1). Because of reductions in reporting and recordkeeping requirements and the flexibility to use an in-house engineer for closed vent system (CVS) certifications, the finalized changes are expected to result in compliance cost savings for affected firms. The PV of these cost savings, discounted at a 7 percent rate, is estimated to be about $189 million dollars, with an EAV of about $33 million (Table 1). Under a 3 percent discount rate, the PV of cost savings is $240 million, with an EAV of $37 million (Table 1).

B. Does this action apply to me?

Categories and entities potentially affected by this action include:

TABLE 2. Industrial Source Categories Affected By This Action

Category

NAICS Code1

Examples of Regulated Entities

Industry . . . .

211120

Crude Petroleum Extraction.

211130

Natural Gas Extraction.

221210

Natural Gas Distribution.

486110

Pipeline Distribution of Crude Oil.

486210

Pipeline Transportation of Natural Gas.

Federal government

. . . .

Not affected.

State/local/tribal government

. . . .

Not affected.

1 North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that the EPA is now aware could potentially be affected by this action. Other types of entities not listed in the table could also be regulated. To determine whether your entity is regulated by this action, you should carefully examine the applicability criteria found in the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the FOR FURTHER INFORMATION CONTACT section, your air permitting authority, or your EPA Regional representative listed in 40 CFR 60.4 (General Provisions).

C. Where can I get a copy of this document?

This final action is available in the docket at www.regulations.gov, Docket ID No. EPA-HQ-OAR-2017-0483. Additionally, following signature by the Administrator, the EPA will post a copy of this final action at https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry. This Web site provides information on all of the EPA's actions related to control of air pollution in the oil and natural gas industry.

D. What is the agency's authority for taking this action?

This action, which finalizes amendments to NSPS OOOOa, is based on the same legal authorities as those for the promulgation of the June 3, 2016, NSPS OOOOa. The EPA promulgated NSPS OOOOa pursuant to its standard setting authority under section 111(b)(1)(B) of the Clean Air Act (CAA) and in accordance with the rulemaking procedures in section 307(d) of the CAA. Section 111(b)(1)(B) requires the EPA to issue "standards of performance" for new sources in a category listed by the Administrator based on a finding that this category of stationary sources causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. CAA section 111(a)(1) defines "a standard of performance" as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated." This definition makes clear that the standard of performance must be based on controls that constitute "the best system of emission reduction ... adequately demonstrated." The standard that the EPA develops, based on the best system of emission reduction (BSER) is commonly a numerical emissions limit, expressed as a performance level (e.g., a rate-based standard). However, CAA section 111(h)(1) authorizes the Administrator to promulgate a work practice standard or other requirements, which reflects the best technological system of continuous emission reduction, if it is not feasible to prescribe or enforce an emissions standard. This action includes proposed amendments to the fugitive emissions standards for well sites and compressor stations, which are work practice standards promulgated pursuant to CAA section 111(h)(1)(A). 81 FR 35829.

The final amendments in this notice result from the EPA's reconsideration of various aspects of the June 3, 2016, NSPS OOOOa. Agencies have inherent authority to reconsider past decisions and to revise, replace, or repeal a decision to the extent permitted by law and supported by a reasoned explanation. FCC v. Fox Televisions Stations, Inc., 556 U.S. 502, 515 (2009); Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co., 463 U.S. 29, 42 (1983) ("State Farm"). "The power to decide in the first instance carries with it the power to reconsider." Trujillo v. Gen. Elec. Co., 621 F.2d 1084, 1086 (10th Cir. 1980); see also, United Gas Improvement Co. v. Callery Properties, Inc., 382 U.S. 223, 229 (1965); Mazaleski v. Treusdell, 562 F.2d 701, 720 (D.C. Cir. 1977).

E. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final rule is available only by filing a petition for review in the United Stated Court of Appeals for the District of Columbia Circuit by [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements. Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, EPA WJC, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding FOR FURTHER INFORMATION CONTACT section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

III. Background

On June 3, 2016, the EPA published a final rule titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Source; Final Rule," at 81 FR 35824 ("2016 NSPS OOOOa"). The 2016 NSPS OOOOa established NSPS for greenhouse gas and VOC emissions from the oil and natural gas sector. For further information on the 2016 NSPS OOOOa, see 81 FR 35824 (June 3, 2016) and associated Docket ID No. EPA-HQ-OAR-2010-0505. Following promulgation of the final rule, the Administrator received petitions for reconsideration of several provisions of the 2016 NSPS OOOOa. Copies of the petitions are provided in the docket for this final rule (Docket ID No. EPA-HQ-OAR-2017-0483). Several states and industry associations sought judicial review of the rule, and the litigation is currently being held in abeyance.

In a letter to petitioners dated April 18, 2017, the EPA granted reconsideration of the fugitive emissions requirements at well sites and compressor stations.3 In a subsequent notice, the EPA granted reconsideration of two additional issues: well site pneumatic pump standards and the requirements for certification of CVS by a professional engineer.4 This action finalizes amendments and clarifications to address these issues, and finalizes amendments to address additional issues in the 2016 NSPS OOOOa that were reconsidered. This action also addresses several implementation questions that were raised following promulgation of the 2016 NSPS OOOOa. The EPA is addressing these issues at the same time to provide clarity and certainty for the public and the regulated community regarding these requirements.

IV. Summary of the Final Standards

A. Well Completions

This final rule amends 40 CFR 60.5375a(a)(1)(iii) to require a separator in close proximity to the well (i.e., onsite or nearby) during flowback so that it can be utilized as soon as it is technically feasible for the separator to function. Locations "near" or "nearby" may include a centralized facility or well pad that services the well affected facility which is used to conduct completion of the well affected facility. We are also amending 40 CFR 60.5375a(a)(1)(i) to clarify the use of a production separator during the initial flowback stage, on the condition that it is also designed to accommodate flowback.

The definition of flowback at 40 CFR 60.5430a is amended in this final rule to exclude screenouts, coil tubing cleanouts, and plug drill outs, as these are functional processes that allow for flowback to begin. We are also adding definitions for screenouts, coil tubing cleanouts, and plug drill outs. Specifically, a screenout is an attempt to clear proppant from the wellbore in order to carry the proppant out of the well. A coil tubing cleanout is a process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. A plug drill-out is the removal of a plug (or plugs) that was used to isolate different sections of the well.

This final rule does not include a definition for a permanent separator. The intent of this definition was to streamline reporting and recordkeeping requirements for flowback routed through production separators, as certain elements associated with well completions (e.g., information about when a separator is hooked up or disconnected) would become unnecessary. However, upon further review, we have determined that this definition will not sufficiently alleviate burden, as these separators may not be permanent fixtures of a site. Instead, we are streamlining reporting and recordkeeping requirements for flowback routed through production separators, on the condition that those separators are designed to accommodate flowback. The details of these streamlined elements are provided in section IV.I.1 of this preamble.

B. Pneumatic Pumps

This final rule expands the technical infeasibility provision for control of a pneumatic pump to all well sites by removing the greenfield site definition from 40 CFR 60.5430a. We previously concluded that circumstances that could otherwise make control of a pneumatic pump technically infeasible at an existing location could be addressed in the design and construction of a new site. However, even at a greenfield site, there may be unique process or control design requirements that may not be compatible with controlling pneumatic pump emissions, such as pressure or capacity requirements for emergency and maintenance flares or other equipment that pneumatic pump emissions are unable to meet. The expansion of the technical infeasibility provision is reflected in 40 CFR 60.5395(b), where paragraphs (1) and (2) have been removed.

In addition, paragraph (3) is amended so that boiler and process heaters are not considered to be control devices or processes. These devices have pressure and capacity requirements for functionality and safety purposes that pneumatic pump emissions are unable to meet.

C. Storage Vessels

This final rule amends the applicability criteria for storage vessel affected facilities by clarifying how the potential for VOC emissions is calculated for one subcategory of storage vessels ("Type 1") and establishes and sets separate performance standards for a second subcategory of storage vessels ("Type 2"). The Type 2 storage vessels are manifolded together with piping such that all vapors are shared between the headspace of the storage vessels, and their emissions, which are shared and indistinguishable, are routed through a closed vent system to a process or a control device with a destruction efficiency of at least 95.0 percent for VOC emissions. As such, they are not the intended target of the current storage vessel performance standard (95 percent reduction of uncontrolled VOC emissions), which applies to storage vessels operating as single storage vessels and is intended to prevent or reduce emissions from being vented into the atmosphere when those emissions are greater than 6 tpy. Further, the current standard already is being applied to Type 2 storage vessels through their design and operation as described above; therefore, subjecting them to the current storage vessel standards achieves no additional emission reduction. The emission source of concern with Type 2 storage vessels are fugitive emissions that could escape from pressure relief devices and covers and while en route to the control device or process. Because such fugitive emissions are included in the definition of fugitive emissions components in 40 CFR 60.5430a and already addressed as part of EPA's BSER analyses and resulting standards for fugitive emissions at well sites and compressor stations, EPA concludes that Type 2 storage vessels are subject to the fugitive emissions requirements applicable to the type of site (i.e., well site or compressor station) where the storage vessel is located.

For all other types of storage vessels (single storage vessels that stand alone or are connected in some way to others but not designed and operated as described above), we are unable to conclude that the design and operation are such that emissions are always shared and indistinguishable among storage vessels and controlled such that the only emissions of concern are the fugitive emissions. Therefore, we are unable to conclude that the BSER for reducing their VOC emissions is the same as the BSER for reducing fugitive emissions at well sites and compressor stations. For these other types of storage vessels that are new or modified, the current storage vessel standard (95 percent emission reduction) continues to apply. These storage vessels will continue to be treated as individual storage vessels and must determine applicability to the control requirements of the rule through the calculation of potential for VOC emissions. If the potential for VOC emissions are greater than 6 tons per year (tpy), based on the maximum average daily throughput, then the storage vessel must meet the control requirements of the rule, including covers and the design and operation of a CVS that routes all vapors to a control device that achieves at least 95.0 percent emission reductions.

We are also finalizing, as proposed, revisions to the definition of maximum average daily throughput to clarify how to determine throughput for the potential for VOC emissions determination.

D. Closed Vent Systems

We are amending the requirements for the no detectable emissions demonstration for CVS for storage vessels and pneumatic pumps. Specifically, we are incorporating the option to demonstrate the storage vessel CVS is operated with no detectable emissions by either monthly audio, visual, or olfactory (AVO) monitoring or optical gas imaging monitoring at the frequencies specified in section IV.E. Similarly, we are incorporating the option to demonstrate the pneumatic pump CVS is operated with no detectable emissions by either an annual inspection using EPA Method 21, monthly AVO monitoring, or optical gas imaging monitoring at the frequencies specified in section IV.E.

Additionally, we are finalizing revisions for certification requirements for CVS design and technical infeasibility for pneumatic pumps. Specifically, we are amending the rule to allow either a professional engineer (PE) or an in-house engineer with expertise on the design and operation of the CVS or pneumatic pump such that the emissions characteristics may be determined for the feasibility of control within existing closed vent system and control device operational limitations.

E. Fugitive Emissions at Well Sites and Compressor Stations

1. Monitoring Frequency

The required fugitive monitoring frequencies for the collection of fugitive emissions components located at a well site or compressor station are as follows:

* Semiannual monitoring for well sites, regardless of production;

* Quarterly monitoring for compressor stations;

* Annual monitoring for well sites and compressor stations located on the Alaska North Slope; and

* Monitoring may be stopped once all major production and processing equipment is removed from a well site such that it contains only one or more wellheads.

2. Modification

This final rule retains the events currently identified in NSPS OOOOa as modification of the collection of fugitive emissions components located at a well site or a compressor station and adds language to specify when a modification of a well site that is a separate tank battery surface site occurs. For the purposes of fugitive emissions components at a well site, a modification occurs when (1) drilling a new well at an existing well site, (2) hydraulically fracturing a well at an existing well site, or (3) hydraulically refracturing a well at an existing well site. Modification of a well site that is a separate tank battery surface site occurs when (1) any of the actions listed above for well sites occurs at an existing separate tank battery surface site, (2) a well modified as described above sends production to an existing separate tank battery surface site, or (3) a well site subject to the fugitive emissions requirements removes all major production and processing equipment such that it becomes a wellhead only well site and sends production to an existing separate tank battery. For the purposes of fugitive emissions components at a compressor station, a modification occurs when (1) an additional compressor at an existing compressor station is installed or (2) one or more compressors at an existing compressor station is replaced with one or more compressor(s) that results in a net increase in the total horsepower of the replaced compressor(s).

3. Initial Monitoring for Well Sites and Compressor Stations

We are amending the initial monitoring requirements to provide 90 days after the startup of production (or startup following modification) for well sites, and 90 days after the startup of a compressor station.

4. Repair Requirements

This final rule amends the fugitive emissions repair requirements. Specifically, we are requiring a first attempt at repair within 30 days of identifying fugitive emissions and final repair within 30 days of the first attempt at repair. We are also finalizing definitions for the terms "first attempt at repair" and "repaired." Specifically, the definition of repaired includes the verification of successful repair through a resurvey of the fugitive emissions component.

5. Definitions Related to Fugitive Emissions at Well Sites and Compressor Stations

We are amending the definition of well site, for purposes of fugitive emissions monitoring, to exclude equipment owned by third parties, saltwater disposal wells, and solid waste disposal wells. The amended definition addresses third party equipment by excluding the flange upstream of the custody meter assembly, and the fugitive emissions component located downstream of this flange. We are also adding definitions for the custody meter as "the meter where natural gas or hydrocarbon liquids are measured for sales, transfers, and/or royalty determination," and the custody meter assembly as "an assembly of fugitive emissions components, including the custody meter, valves, flanges, and connectors necessary for the proper operation of the custody meter." The exemption is limited within the definition of a well site to the flange upstream of the custody meter and does not include other third-party equipment at a well site.

This final rule amends the definition of well site to exclude Underground Injection Control (UIC) Class I non-hazardous solid waste disposal wells and UIC Class II oilfield wastewater disposal wells. These disposal wells are regulated through UIC programs under the Safe Drinking Water Act for surface and groundwater protection. Additionally, we are adding definitions for UIC Class I non-hazardous solid waste disposal well and UIC Class II oilfield disposal well to distinguish them from injection wells subject to the fugitive emissions monitoring and repair requirements in the rule. The definition for a UIC Class I non-hazardous solid waste disposal well is "a well with a UIC Class I permit used to inject non-hazardous wastes into deep, confined rock formations. Class I wells are disposal wells which inject fluids beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water." The definition for a UIC Class II oilfield disposal well is "a well with a UIC Class II permit where wastewater resulting from oil and natural gas production operations is injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata." Further, UIC Class I and UIC Class II disposal facilities without wells that produce oil or natural gas are not considered well sites for the purposes of fugitive emissions requirements.

We are finalizing, as proposed, the definition of startup of production as it relates to fugitive emissions requirements. Specifically, startup of production is defined as "the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water, except as otherwise provided herein. For the purposes of the fugitive monitoring requirements of §60.5397a, startup of production means the beginning of the continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water."

F. Alternative Means of Emission Limitation (AMEL)

1. Incorporation of Emerging Technologies

We are amending the application requirements for requesting the use of an AMEL for well completions, reciprocating compressors, and the collection of fugitive emissions components located at a well site or compressor station. Applications for an AMEL may be submitted by, among others, owners or operators of affected facilities, manufacturers or vendors of leak detection technologies, or trade associations. The application must provide sufficient information to demonstrate that the AMEL achieves emission reductions at least equivalent to the work practice standards in this rule. At a minimum, the application should include field data that encompasses seasonal variations, and may be supplemented with modeling analyses, test data, and/or other documentation. The specific work practice(s), including performance methods, quality assurance, the threshold that triggers action, and the mitigation thresholds are also required as part of the application. For example, for a technology designed to detect fugitive emissions, information such as the detection criteria that indicates fugitive emissions requiring repair, the time to complete repairs, and any methods used to verify successful repair would be required.

2. Incorporation of State Fugitive Emissions Programs

This final rule includes alternative fugitive emissions standards for specific state fugitive emissions program that the EPA has concluded are at least equivalent to the fugitive emissions monitoring and repair requirements at 40 CFR 60.5397a(e), (f), (g), and (h). These alternative fugitive emissions standards may be adopted for certain individual well sites or compressor stations that are subject to fugitive emissions monitoring and repair so long as the source complies with specified federal requirements applicable to each approved alternative state program. For example, a well site the is subject to the requirements of Pennsylvania General Permit 5A, section G, effective August 8, 2018, could comply with those standards in lieu of the monitoring, repair, recordkeeping, and reporting requirements in the NSPS. However, the company must develop and maintain a fugitive emissions monitoring plan, as required in 40 CFR 60.5397a(c) and (d) and must monitor all of the fugitive emissions components as defined in 40 CFR 60.5430a, regardless of the definition used in the alternative standard. Additionally, the company must submit, as an attachment to the annual report, the report that is submitted to their state, in the format submitted to the state, or the information required in the report for NSPS OOOOa if the state report does not include site-level monitoring and repair information. If a well site is located in the state but is not subject to the requirements for monitoring and repair (i.e., not obligated to monitor or repair fugitive emissions), the well site must continue to comply with the requirements of 40 CFR 60.5397a in its entirety.

In addition to providing alternative fugitive emissions standards for well sites and compressor stations located in California, Colorado, Ohio, Pennsylvania, and Texas, and well sites in Utah, these amendments provide application requirements to request alternative fugitive emissions standards as state, local, and tribal programs continue to develop. Applications for alternative fugitive emissions standards based on state, local, or tribal programs may be submitted by any interested person, including individuals, corporations, partnerships, associations, states, or municipalities. Similar to the applications for AMEL for emerging technologies, the application must include sufficient information to demonstrate the alternative fugitive emissions standards achieve emissions reductions at least equivalent to the fugitive emissions monitoring and repair requirements in this rule. At a minimum, the application must include the monitoring instrument, monitoring procedures, monitoring frequency, definition of fugitive emissions requiring repair, repair requirements, recordkeeping, and reporting requirements.

G. Onshore Natural Gas Processing Plants

1. Capital Expenditure

We are amending the definition of "capital expenditure" at 40 CFR 50.5430a by replacing the equation used to determine the percent of replacement cost, "Y". The final equation for "Y" is based on the consumer price indices (CPI), where "Y" equals the CPI of the date of construction or reconstruction divided by the CPI of the date of component price data, or "CPIN/CPIPD.

2. Equipment in VOC service less than 300 hours/year

We are amending the requirements for equipment leaks at onshore natural gas processing plants. Specifically, we are including an exemption from monitoring for equipment that an owner or operator designates as being in VOC service less than 300 hr/yr. This exemption applies to equipment at onshore natural gas processing plants that is used only during emergencies, used as a backup, or that is in service only during startup and shutdown.

3. Initial Compliance Period

We are amending NSPS OOOOa to clarify that the initial compliance deadline for the equipment leak standards for onshore natural gas processing plants is 180 days. Specifically, we are including in NSPS OOOOa the provision requiring compliance "as soon as practicable, but no later than 180 days after initial startup" that is at 40 CFR 60.632(a) of subpart KKK, "Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or before August 23, 2011" (NSPS KKK). In 2012, based on its review of NSPS KKK, the EPA revised this existing NSPS by lowering the leak definition for valves from 10,000 ppm to 500 ppm and requiring the monitoring of connectors. 77 FR 49490, 49498. The EPA did not discuss any change to the compliance deadlines in NSPS KKK. However, 40 CFR 60.632(a) was not included in the revised NSPS KKK, which was promulgated as part of NSPS OOOO and later carried over into NSPS OOOOa. During the rulemaking for NSPS OOOOa, the EPA declined a request to include the language in 40 CFR 60.632(a) in NSPS OOOOa, explaining that such inclusion was not necessary because NSPS OOOOa already incorporates by reference a similar statement (i.e., 40 CFR 60.482-1a(a)) which requires each owner and operator to "demonstrate compliance ...within 180 days of initial startup," 80 FR 56593, 56647-8. However, it appears that there is ongoing confusion, in particular with respect to the initial compliance deadline for the specific requirements in the rule that each pump in light liquid service and each valve in gas/vapor or light liquid service must be monitored monthly (before moving to any skip period). In assessing the issue, the EPA notes that NSPS KKK includes both 40 CFR 60.632(a) and 40 CFR 60.482-1(a), a provision that is the same as 40 CFR 60.482-1a(a), suggesting that the EPA did not think that 40 CFR 60.482-1(a) (and 40 CFR 60.482-1a(a)) make 40 CFR 60.632(a) redundant or unnecessary. Consistent with NSPS KKK, the EPA is amending NSPS OOOOa to include a provision similar to 40 CFR 60.632(a).

The amendment clarifies that monitoring must begin as soon as practicable but no later than 180 after initial startup. Once started, monitoring must continue with the required schedule. For example, if pumps are monitored by month 3 of the initial startup period, then monthly monitoring is required from that point forward. This initial compliance period is different than the compliance requirements for newly added pumps and valves within a process unit that has an existing leak detection and repair (LDAR) program. Initial monitoring for newly added pumps and valves continues to be required within 30 days of the startup of the pump or valve (i.e., when the equipment is first in VOC service).

H. Sweetening Units

We are amending the applicability of standards for sweetening units to clarify that all sweetening units processing natural gas are subject to the standards.

I. Recordkeeping and Reporting

We are amending NSPS OOOOa to streamline the recordkeeping and reporting requirements as discussed below for the specified affected facilities.

1. Well Completions

For each well affected facility that routes flowback entirely through one or more production separators that are designed to accommodate flowback, owners and operators are only required to record and report the following elements:

* Well Completion ID;

* Latitude and longitude of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using North American Datum of 1983;

* US Well ID; and

* The date and time of the startup of production.

2. Fugitive Emissions at Well Sites and Compressor Stations

* Revise the requirements in paragraph 60.5397a(d)(1) to require procedures that ensure

all fugitive emissions components are monitored during each survey, in place of the sitemap and observation path.

* Remove the requirement to maintain records of the number and type of fugitive emissions components or digital photo of fugitive emissions components that are not repaired during the monitoring survey.

* Require records of the date of first attempt at repair and date of successful repair and remove records of date and method of other repair attempts.

* Revise reporting to specify the type of site (i.e., well site, low production well site, or compressor station) and when the well site changes status to a wellhead only well site.

* Remove requirement to report the name or ID of operator performing the monitoring survey.

* Remove requirement to report the number and type of difficult-to-monitor and unsafe-to-monitor components that are monitored during each monitoring survey.

* Remove requirement to report the date of successful repair.

* Remove requirement to report the type of instrument used for resurvey.

In addition to streamlining the recordkeeping and reporting requirements, we are also finalizing the form that is used for submitting annual reports to the Compliance and Emissions Data Reporting Interface (CEDRI).

J. Technical Corrections and Clarifications

We are revising NSPS OOOOa to include the following technical corrections and clarifications.

* Revise paragraphs 60.5385a(a)(1), 60.5410a(c)(1), 60.5415a(c)(1), 60.5420a(b)(4)(i), and 60.5420a(c)(3)(i) to clarify that hours or months of operation at reciprocating compressor facilities should be measured beginning with the later of initial startup, the effective date of the requirement (August 2, 2016), or the last rod packing replacement.

* Revise paragraph 60.5393a(b)(3)(ii) to correctly cross-reference to paragraph (b)(3)(i) of that section.

* Revise paragraph 60.5397a(c)(8) to clarify the calibration requirements when Method 21 of Appendix A-7 to Part 60 is used for fugitive emission monitoring.

* Revise paragraph 60.5397a(d)(3) to correctly cross-reference paragraphs (g)(3) and (g)(4) of that section.

* Revise paragraph 60.5401a(e) to remove the word "routine" to clarify that pumps in light liquid service, valves in gas/vapor service and light liquid service, and pressure relief devices in gas/vapor service within a process unit at an onshore natural gas processing plant located on the Alaskan North Slope are not subject to any monitoring requirements.

* Revise paragraph 60.5410a(e) to correctly reference pneumatic pump affected facilities located at a well site as opposed to pneumatic pump affected facilities not located at a natural gas processing plant. This proposed revision reflects that the 2016 NSPS OOOOa did not finalize requirements for pneumatic pumps in the gathering and boosting and transmission and storage segments. 81 FR 35850.

* Revise paragraph 60.5411a(a)(1) to remove the reference to paragraphs 60.5412a(a) and (c) for reciprocating compressor affected facilities.

* Revise paragraph 60.5411a(d)(1) to remove the reference to storage vessels, as this paragraph applies to all the sources lists in paragraph 60.5411a(d), not only storage vessels.

* Revise paragraphs 60.5412a(a)(1), 60.5412a(a)(1)(iv), 60.5412a(d)(1)(iv), and 60.5412a(d)(1)(iv)(D) to clarify that all boilers and process heaters must introduce the vent stream into the flame zone and that the performance requirement option for combustion control devices on centrifugal compressors and storage vessels is to introduce the vent stream with the primary fuel or as the primary fuel. This is

consistent with the performance testing exemption in section 60.5413a and continuous monitoring exemption in section 60.5417a for boilers and process heaters that introduce the vent stream with the primary fuel or as the primary fuel.

* Revise paragraph 60.5412a(c) to correctly reference both paragraphs (c)(1) and (c)(2) of that section, for managing carbon in a carbon adsorption system.

* Revise paragraph 60.5413a(d)(5)(i) to reference fused silica-coated stainless steel evacuated canisters instead a specific name brand product.

* Revise paragraph 60.5413a(d)(9)(iii) to clarify the basis for the total hydrocarbon span for the alternative range is propane, just as the basis for the recommended total hydrocarbon span is propane.

* Revise paragraph 60.5413a(d)(12) to clarify that all data elements must be submitted for each test run.

* Revise paragraph 60.5415a(b)(3) to reference all the applicable reporting and recordkeeping requirements.

* Revise paragraph 60.5416a(a)(4) to correctly cross-reference paragraph 60.5411a(a)(3)(ii).

* Revise paragraph 60.5417a(a) to clarify requirements for controls not specifically listed in paragraph (d) of that section.

* Revise paragraph 60.5422a(b) to correctly cross-reference paragraphs 60.487a(b)(1) through (3) and (b)(5).

* Revise paragraph 60.5422a(c) to correctly cross-reference paragraph 60.487a(c)(2)(i) through (iv) and (c)(2)(vii) through (viii).

* Revise paragraph 60.5423a(b) to simplify the reporting language and clarify what data is required in the report of excess emissions for sweetening unit affected facilities.

* Revise paragraph 60.5430a to remove the phrase "including but not limited to" from the "fugitive emissions component" definition. This proposed revision reflects that in the response to comments document for NSPS OOOOa we stated we were removing this phrase.5

* Revise paragraph 60.5430a to remove the phrase "at the sales meter" from the "low pressure well" definition. When determining the low pressure status of a well, pressure is measured within the flow line, rather than at the sales meter.

* Revise Table 3 to correctly indicate that the performance tests in section 60.8 do not apply to pneumatic pump affected facilities.

* Revise Table 3 to include the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station in the list of exclusions for notification of reconstruction.

* Revise paragraphs 60.5393a(f), 60.5410a(e)(8), 60.5411a(e), 60.5415a(b), 60.5415a(b)(4), 60.5416a(d), 60.5420a(b), 60.5420a(b)(13), and introductory text in 60.5411a and 60.5416a to remove the language added in the "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Grant of Reconsideration and Partial Stay" (June 5, 2017), which was vacated by the U.S. Court of Appeals for the D.C. Circuit on July 3, 2017.

V. Significant Changes Since Proposal

This section identifies significant changes in this rule from the proposed rule. These changes reflect the EPA's consideration of over 500,000 comments submitted on the proposal and other information received since the proposal. In this section we discuss the significant changes since proposal by affected facility type and the rationales for those changes. Additional information related to these changes, such as specific comments and our responses, is in section VI of this preamble and in materials available in the docket.6

A. Storage Vessels

In the October 15, 2018, proposal, we proposed clarifications to the applicability determination for storage vessels. Specifically, we proposed amendments to the definition of "maximum average daily throughput" that provided distinct methodologies for calculating the throughput of an individual storage vessel based on how throughput is measured and recorded. The reasons we proposed the amendments were based on there being expressed confusion over how to calculate this throughput, and we were concerned that some operators may be incorrectly averaging emissions across storage tanks in tank batteries when determining the potential for VOC emissions.

Commenters expressed objections to several aspects of these amendments, with the most ardent objections being related to the EPA's assumptions regarding the averaging of emissions across storage tanks in tank batteries. Commenters asserted there is no practical logic for the EPA not allowing operators to average emissions over a tank battery with a common shared vapor space. The commenters explained that the EPA's proposal is not technically valid and why averaging has a sound basis in engineering, and importantly, why averaging addresses the EPA's concern about flash emissions.

Specifically, the commenters pointed out that tank batteries, controlled by a common flare or combustor system or vented through one common pressure relief valve (PRV), typically share vapor space (the tank volume above the liquid) and joint piping used to collect generated vapors and convey them to the control device. The commenters noted that vapors flow both into and out of each tank within the battery and into overflow piping on a continuous basis, and vapors will always flow from high pressure areas to low pressure areas when flow is mechanically unrestricted. In this configuration, the commenters explain that the flash emissions from the first tank will flow into the other tanks and vent line space associated with the battery as a whole until the total pressure in the system exceeds the back-pressure of the flares, control device, or in systems without controls, the PRV. The commenters asserted that only then will the emissions be released from either the PRV or combusted by the control equipment. The commenters contended that since gas equalizes among the tank vessels in a manifolded system, there is no technical basis for the EPA's concern about emissions from the first storage vessel in the series being underestimated, or that averaging across all storage vessels underestimates the emissions per vessel. The commenters noted that the determinant factor for allowed averaging across multiple storage vessels within a system is shared vapor space, rather than the EPA's proposed focus of liquid filling configuration.

Commenters also pointed out that the proposed amendment ignores that most new tank batteries not subject to NSPS OOOOa are already controlled under state regulations or permits, and that the EPA's clarification would completely upend the methodology that many operators have been using to determine applicability under NSPS OOOOa. The commenter expressed that they believe that the EPA's proposal represents far more than a "clarification" and it raises significant concerns about inappropriate retroactive application and enforcement.

These comments, and subsequent conversations with the commenters, resulted in a reexamination of the applicability of the current storage vessel standards to the type of storage vessels described above.

First, we reconsidered the case where storage vessels are operated as a system where the storage vessels are manifolded together, through piping, such that the vapors in the headspace of each storage vessel are shared between all storage vessels. That is, as liquids are introduced to one storage vessel, the vapors are transferred to the piping, or common header, and enter the common vapor space. When the vapor pressure of the common header reaches a specified set point, the vapors are typically conveyed through a CVS to either a vapor recovery unit (VRU) or a control device. Where this manifolded system of storage vessels is designed and operated to route the vapors in this manner the system becomes a single emission point, instead of each individual storage vessel representing individual emission points for flash emissions. This is in contrast to the concept upon which the individual storage vessel applicability was established in 2012 for this source category and suggests that systems of storage vessels manifolded together are a different class or type that should have emissions and controls evaluated differently than how we evaluated the individual storage vessels.

In evaluating these manifolded storage vessel systems, we considered where the specific emission points are located and what controls or work practices are appropriate to further reduce those emissions. With the manifolded storage vessel systems described in the previous paragraph, there are 2 potential emission points, the control device and fugitive emissions components located within the system, such as the CVS and pressure relief devices (PRDs) on the storage vessel (e.g., thief hatches or pressure relief valves). The emissions from the control device are influenced by several factors, including the destruction-efficiency and operation of the device. The existing requirements for storage vessel affected facilities include the use of control devices that reduce VOC emissions by 95%. For purposes of our examination of manifolded storage vessel systems, we concluded the control devices used would also achieve 95% control of VOC emissions. Therefore, no additional emission reductions would be achieved from the manifolded storage vessel system if it were subject to the control requirements for individual storage vessels. That is, in both cases, emissions are reduced by 95% with the use of add-on controls. Therefore, we concluded that storage vessels in manifolded tank systems that are routed to a control device that achieves 95% control, or routed back to the process, should not be storage vessel affected facilities as defined in the 2016 NSPS OOOOa.

Next, we evaluated the second emission point, fugitive emissions components on the storage vessel and the CVS components. Under the existing rule, the cover and CVS associated with storage vessel affected facilities are subject to the cover, CVS, and control requirements in 40 CFR 60.5411a and 60.5395a. However, where the storage vessel is not subject to the cover, CVS, and control requirements in 40.CFR 60.5411a and 60.5395a, such fugitive emissions are included in the definition of fugitive emissions components in 40 CFR 60.5430a and considered in the EPA's BSER analyses and resulting standards for the collection of fugitive emissions components at well sites and compressor stations. While we have not evaluated the cost effectiveness of applying the fugitive requirements to this type of storage vessel alone (as opposed to all the fugitive components on that site), it is our understanding that where this type of storage vessel is newly constructed or modified (i.e., adding an additional storage vessel)7 at a well site or compressor station, inevitably it is due to an increase in production that increases throughput, resulting in the "modification," as that term is defined for purposes of the fugitive requirements, where these storage vessels are located.

Therefore, in evaluating the manifolded storage vessel system described above, we have concluded that the existing fugitive emissions requirements that will apply are appropriate to reduce emissions from these emission points without any changes to the rule.

After consideration of the manifolded storage vessel systems, we are amending the applicability of the rule for storage vessels to subcategorize storage vessels based on 2 distinct types: (1) an individual storage vessel that is not part of a manifolded storage vessel system ("Type 1"), and (2) a storage vessel that is part of a manifolded storage vessel system that meets specific design requirements ("Type 2"). The design requirements for these Type 2 systems are (1) the storage vessels are manifolded together with piping such that all vapors are shared between the headspace of the storage vessels, (2) the storage vessels are equipped with a CVS that is designed and operated to route vapors back to the process or to a control device, and (3) the control device has a manufacturer-designed destruction efficiency of at least 95% for VOC emissions. Where an owner or operator has a manifolded tank system that meets some of the Type 2 design specifications above, but not the 95% control requirement, the storage vessel would be considered to be a Type 1 storage vessel and the potential VOC emissions must be determined on an individual uncontrolled storage vessel basis.

For the individual storage vessel, that is not part of a manifolded system that meets the Type 2 design specifications (i.e., a Type 1 storage vessel), we are finalizing, as proposed, the definition of "maximum average daily throughput" and requiring calculation of potential VOC emissions on an individual storage vessel basis.

B. Fugitive Emissions at Well Sites and Compressor Stations

The reconsideration of the fugitive emissions requirements at well sites and compressor stations was focused on identifying areas to reduce the administrative burden of requirements and provide flexibility for future innovation, without compromising the environmental benefit achieved through reducing emissions. In the June 3, 2016, final rule, we concluded that the BSER for reducing fugitive emissions at well sites and compressor stations is to detect fugitive emissions using optical gas imaging (OGI) and repair or replace detected leaking fugitive components.8 81 FR 35826. In our October 15, 2018 proposal, while we continued to maintain OGI as the BSER for reducing fugitive emissions at well sites and compressor stations, we identified three areas of uncertainties that led us to believe that we might have overestimated the emission reduction and therefore cost effectiveness of the currently required monitoring frequencies (i.e., semiannual monitoring at well sites and quarterly monitoring at compressor stations). We proposed reduced monitoring frequencies to reduce the cost burden of the requirements and solicited comments on these areas of uncertainty as well as additional information for us to better assess emission reductions at different monitoring frequencies. As discussed below, after evaluating the comments and information received, we have addressed the three areas of uncertainty, and conclude the current monitoring frequencies are cost effective; we are therefore not finalizing the proposed reduced monitoring frequencies which would result in forgone emission reductions and thus a less effective program. Separate from the issue of monitoring frequencies discussed above, commenters expressed concern that EPA has not reconsidered the administrative burden due to the extensive recordkeeping and reporting requirements of the fugitive emissions program, which commenters stated is the largest cost of the program and had previously been underestimated. Therefore, we reexamined all aspects of the fugitive emissions program and agree with commenters that the administrative burden is substantial and continues to increase for owners and operators as more sources become subject to the requirements of the rule.

First, we examined the commenters' assertions that the recordkeeping and reporting costs were underestimated in the June 3, 2016, final rule and the October 15, 2018, proposed reconsideration. To better understand the recordkeeping and reporting costs associated with the existing standards, we first reviewed the specific recordkeeping and reporting requirements for the fugitive emissions program, including the monitoring plan. In the October 15, 2018, proposal, we had proposed to reduce cost burden through reducing monitoring frequencies. While we updated portions of the model plant analysis for fugitive emissions, we did not make specific changes related to recordkeeping and reporting costs. As shown in the proposal Technical Support Document (TSD),9 development of a monitoring plan was estimated as a one-time cost of $3,672 per company-defined area, which is estimated as 22 well sites, 7 gathering and boosting compressor stations, or each transmission and storage compressor station. Reporting costs were estimated at $245 per site per year. While there were other specific line items in the estimates that could be interpreted as recordkeeping costs, such as initial and subsequent activities planning, we were unable to conclude these represented actual recordkeeping costs in our review of the estimates for the existing standards. This lack of appropriate cost estimation aligns with the commenters' claims that cost burden was underestimated for the fugitive emissions requirements.

We used information provided by the commenters to reevaluate the cost burden of the existing fugitive emissions standards prior to considering any additional changes to the standards that would further reduce the cost burden. This is important because it provides a baseline for comparison when determining any burden reductions associated with changes to the standards. First, before considering the comments, we removed certain line items from the previous analysis. We removed the initial and subsequent planning activities because these items were not representative of actual recordkeeping activities that are associated with the fugitive emissions requirements of the rule. We also removed the cost associated with notification of initial compliance status because such notification is not required under the current rule. Next, we considered the comments and information received on our estimate of the cost to develop a monitoring plan. One commenter provided information on the range of costs that have been incurred by owners and operators to develop a monitoring plan since the rule has been in place.10 These estimated costs range from $5,600 to $8,800, which is more than our estimate of $3,672. In examining the information provided by the commenter in further detail, we note that hourly rates are higher than the standard labor rate used in EPA's calculations, which could attribute to the difference in costs. Next, commenters dispute our assumption that the monitoring plan is a one-time cost for the company. Several commenters stated while most of the monitoring plan is associated with a one-time cost, the required site map and observation path require frequent updates as the equipment at the site changes. One of these commenters provided an estimate of the cost to develop the initial site map and observation path for an individual site, and the cost of updating these items for each monitoring survey.11 This information provided estimates that companies have already spent approximately $650 developing the individual site map and observation path for each site and an additional $150 updating these items for each monitoring survey. Based on this information, we agree it is appropriate to account for the necessary updates for the site map and observation path when estimating the cost burden of the rule. Therefore, we split the monitoring plan costs into three items in our model plant analysis: (1) develop company-wide fugitive emissions monitoring plan, (2) develop site-specific fugitive monitoring plan (i.e., site map and observation path), and (3) management of change (site map and observation path). The updated estimates associated with developing a monitoring plan for well sites under the existing standards are $2,448 to develop the general company-wide monitoring plan (assumes 22 well sites), $400 to develop the site map and observation path for each site, and $184 to update the individual site map and observation path annually (based on semiannual monitoring). For gathering and boosting compressor stations, we estimate it costs $1,530 to develop a company-wide monitoring plan (assumes 7 stations per plan), $400 to develop the site map and observation path for each site, and $367 to update the individual site map and observation path annually (based on quarterly monitoring). For both transmission and storage compressor stations, we maintain the estimate of $3,672 to develop a site-specific monitoring plan and have added $367 to update the individual site map and observation path annually (based on quarterly monitoring). Based on available information, we believe these costs are representative of the costs to develop and maintain the monitoring plan as required in the 2016 NSPS OOOOa.

We then examined the recordkeeping costs associated with the fugitive emissions requirements. As stated above, we were unable to locate specific estimates for recordkeeping costs for the existing standards, therefore, all costs are new in our baseline estimate of the actual cost of the existing standards and are based on information received from commenters and previous information collected by the Agency for similar programs. There are extensive records required for each survey that is performed, regardless of the frequency, therefore we recognize that appropriate data management is critical to ensuring compliance with the standards. As explained in the TSD for this final rule12 we evaluated costs for the set-up for a database system which ranged from commercially available options to customized systems. Because there are commercial systems currently available that allow owners and operators to maintain records in compliance with the standards, we did not find it appropriate to apply customized system costs to determine an average or range of costs. Therefore, our initial database set-up fee is estimated as $18,607 for 22 well sites, 7 gathering and boosting stations, or each transmission and storage compressor station. In addition to this initial set-up fee, we recognize that there are annual licensing fees that include technical support and updates to software. Therefore, we have incorporated an ongoing annual fee of approximately $470. Finally, there is recordkeeping associated with tracking observed fugitive emissions and repairs, such as scheduling repairs and quality control of the data. Based on information provided by commenters13 we estimate additional recordkeeping costs at $430 for well sites and $860 for compressor stations.

Finally, we evaluated the current estimate for reporting costs associated with the existing standards. One commenter asserted they spent over 500 hours reporting information through CEDRI for their sources.14 We examined the information reported to CEDRI for this commenter and concluded they have reported information for approximately 100 well sites, which would equate to 5 hours per site. This is similar to our estimate of 4 hours per well site, therefore we did not update the reporting cost estimate when determining the actual costs of recordkeeping and reporting associated with the existing standards.

In summary, we updated the cost burden estimates for recordkeeping and reporting based on the 2016 NSPS OOOOa. The updated annualized recordkeeping and reporting costs for the existing rule, on a per site basis, are approximately $1,500 per well site, $2,500 per gathering and boosting station, and $5,700 per transmission and storage station. These costs represent the baseline from which any changes to the cost burden for reporting and recordkeeping requirements in this final rule are compared.

After updating the recordkeeping and reporting costs for the existing requirements, we evaluated requests by commenters recommending specific changes to those requirements. Several commenters requested removal of or amendments to specific line items. These included items such as the site map and observation path requirement in the monitoring plan, records related to the date and repair method for each repair attempt, and name of the operator performing the survey. After further review of the specific requirements, for the reasons explained below, we agree with the commenters that some of the items are unnecessary or redundant for demonstrating compliance or are an unnecessary burden.

We are amending the monitoring plan by removing the requirement for a site map and observation path when OGI is used to perform fugitive emissions surveys. This requirement was in place to ensure that all fugitive emissions components would be imaged during each survey. Through further examination, we agree with the commenters that a site map and observation path are only one way to ensure all components are imaged. We are replacing the specified site map and observation path with a requirement to include procedures to ensure that all fugitive emissions components are monitored during each survey. These procedures may include a site map and observation path, an inventory, or narrative of the location of each fugitive emissions component, but may also include other procedures not listed here. These company-defined procedures are consistent with other requirements for procedures in the monitoring plan, such as the requirement for procedures for determining the maximum viewing distance and maintaining this viewing distance during a survey. As previously stated, we had not accurately accounted for the ongoing cost of updating the site map and observation path as changes occur at the site. Based on information provided by one commenter, we estimate this amendment will save each site $580 with the semiannual monitoring frequency. These cost savings are based on an initial cost of $400 to develop the site map and observation path, plus $180 to update the site map or observation path each year, based on a semiannual monitoring frequency.

We are amending the recordkeeping requirements to remove the requirement to keep records of each repair attempt and the number and type of components not repaired during the monitoring survey. We are removing the requirement to record each repair attempt because the repair requirements are specific to completing a first attempt at repair within 30 days of finding the fugitive emissions and completing repair, including a resurvey, within 30 days of the first attempt at repair. Other interim repair attempts are not vital for demonstrating compliance with the repair requirements. The 2016 rule required maintaining a record of the number and type of components found with fugitive emissions that were not repaired during the monitoring survey. After further review, this information is redundant to other records of the survey date and repair dates required for all fugitive emissions components, regardless of if repairs are completed during the monitoring survey. While it is difficult to quantify the reduction in cost burden of the removal of these records, we have estimated a reduction in cost of 25%, or $107 per site per year.

We are also amending the reporting requirements to streamline reporting based on comments received and further reconsideration of what information is vital to demonstrate compliance with the standards. First, as we are finalizing the requirement for electronic reporting through this action, we are updating the CEDRI template to streamline data entry and ease review of the information for compliance purposes. Specifically, for reporting compliance with the fugitive emissions requirements, we have created dropdown menus for the operator to select the type of site for which they are reporting (e.g., well site or compressor station), indication of if the well site changed status to a wellhead only well site during the reporting period, and indication of whether an approved alternative fugitive emissions standard was used during the reporting period for the site. Second, we are removing specific items from the annual report as listed in section IV.I.3 of this preamble. We are removing the requirement to report the name or unique ID of the operator performing the survey, however this information must be maintained in the record, similar to the LDAR requirements for onshore natural gas processing plants. We are removing the requirement to report the number and type of difficult-to-monitor and unsafe-to-monitor components that were monitored during the specified survey. This information is required to be kept in the record, and the type and number of these components would already be included in the reported number and type of components found with fugitive emissions during the survey. The date of successful repair is being removed from the report because we already require owners and operators to report the number and type of fugitive emissions not repaired on time. The date of successful repair will be maintained in the record. Finally, the type of instrument used for the resurvey is being removed from the report because this information does not directly inform a compliance demonstration from the report. Similar to the recordkeeping changes identified in the previous paragraph, it is difficult to estimate the reduced cost burden of each of these individual items. Therefore, we have estimated a burden reduction of 25%, or $61 per site per annual report.

In summary, the cost burden estimates for recordkeeping and reporting based on the amendments in this final rule will reduce the burden of the rule. The estimated annualized recordkeeping and reporting costs for this final rule, on a per site basis, are approximately $1,100 per well site, $1,750 per gathering and boosting station, and $5,000 per transmission and storage compressor station. This results in an annualized burden reduction of approximately 27% for well sites, 30% for gathering and boosting compressor stations, and 12% for transmission and storage compressor stations.15

After updating the recordkeeping and reporting costs, we reexamined the other elements of the model plant analysis based on comments and data received. In the October 15, 2018, proposal, we stated that "EPA identified three areas of the analysis that raise concerns regarding the emissions reduction: (1) the percent emission reduction achieved by OGI, (2) the occurrence rate of fugitive emissions at different monitoring frequencies, and (3) the initial percentage of fugitive emissions components identified with fugitive emissions." 83 FR 52063. Given these areas of concern, we solicited information to further refine our analysis and reduce or eliminate these uncertainties. We received information from several commenters that we used to evaluate each of these uncertainties for this final rule.

First, in the October 15, 2018, proposal the EPA maintained the estimates for emissions reductions achieved when using OGI of 30 percent for biennial monitoring, 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring. As stated in the proposal, one stakeholder raised concerns that the estimated control efficiency for quarterly monitoring should be 90 percent instead of 80 percent and annual monitoring should be 80 percent instead of 40 percent, based on their interpretation of results by the Canadian Association of Petroleum Producers (CAPP).16 In response to this information, the EPA reviewed the report and was unable to conclude that annual OGI monitoring would achieve 80 percent emissions reductions, as stated by the stakeholder.17 In their submission of public comments, and in subsequent clarifying discussions, the commenter continues to assert that the EPA has understated the emissions reductions achieved with annual monitoring.18 As discussed below, we have reevaluated the information provided in the CAPP report and other publications and continue to conclude that annual OGI monitoring achieves 40 percent emissions reductions.

In 2005 CAPP issued a national inventory of greenhouse gas, criteria air contaminant, and hydrogen sulphide emissions by the upstream oil and gas industry.19 In 2007, CAPP developed Best Management Practices (BMPs) for fugitive emissions from upstream oil and gas.20 While not a regulation, these BMPs included recommended methods to reduce fugitive emissions, including the adoption of a directed inspection and maintenance program and the use of specific controls. In 2014, CAPP issued a report that updated the emissions factors developed in 2005, and that report estimated a new-weighted decrease of component-specific emissions of approximately 75 percent.21

The EPA evaluated these three reports to determine if the control efficiency of OGI should be adjusted. First, we evaluated the information in Tables 9 and 10 of the 2014 report. These tables include the emissions factors estimated using the two methodologies discussed in the 2014 report (Table 9) and the final updated emissions factors after consolidation of the two methodologies (Table 10). Table 10 also provided leaker counts and component counts. While there is uncertainty related to the component counts, we used these counts as is to determine the emissions from leakers, in kilograms per hour (kg/hr) using both the 2005 and updated 2014 emissions factors. We then used the recommended monitoring frequencies in Table 4 of the 2007 CAPP BMPs to assign the emissions based on monitoring frequency. With this information, we were able to determine the difference in emissions between the 2005 and 2014 reports for individual components.

Through this analysis we noted that open-ended lines had higher emissions than compressor seals in the 2005 inventory, with approximately 90 percent reductions in the 2014 study. Therefore, we examined open-ended lines in further detail. In the 2005 report, the confidence limits for open-ended lines are -60% to +170%, which means there is essentially no confidence in the emissions factors for this component type. This alone would indicate that any updated emissions factors in 2014 are not attributed to emissions reductions but are attributed to more or better information that decreases the uncertainty of the emissions factor. Further examination of the 2005 inventory shows that open-ended lines were assigned a control factor of 1, which results in a leak rate of 0. This control factor assumes that all open-ended lines are equipped with a closed device (e.g., cap, plug, blind flange, or secondary valve). In the 2014 report, the average emissions factor for open-ended lines was determined using the total reported emissions for open-ended lines plus the total "no leak" emissions (using factors developed in 1992) divided by the total number of open-ended lines monitored. As previously stated, there is considerable uncertainty in the number of open-ended lines that were actually monitored at the facilities included in the 2014 report. While the 2014 report states that open-ended lines fitted with a closure device are not considered open-ended lines, there is uncertainty about whether the only reported leaks are from open-ended lines that are not controlled, especially since the BMPs specifically state a closure device should be used to control emissions. Given the uncertainties in the 2005 emissions factor, the control status of open-ended lines, and the component counts, we are unable to conclude the difference in emissions is due solely to annual monitoring using OGI. Despite this uncertainty, if we assumed the differences were due to monitoring alone, it is important to determine which open-ended lines are monitored annually and which are monitored quarterly. To do that, we evaluated Tables 12 and 13 of the 2014 report, which include default component counts by equipment or process (Table 12) and number of equipment or processes per jurisdiction reporting (Table 13). This allowed us to estimate the number of open-ended lines associated with compressors (and likely monitored quarterly), which we estimate is 65% of the open-ended lines. Attributing the emissions from 65% of the open-ended lines to quarterly monitoring results in emissions reductions of 92% for quarterly monitoring and 56% for annual monitoring. Based on this analysis, we are unable to conclude that annual OGI monitoring would achieve an 80% reduction in emissions as stated by the commenter.

Another commenter provided information related to the emissions reductions achieved when using OGI at the various monitoring frequencies.22 In their comments, a study performed by Dr. Arvind Ravikumar is referenced as supporting the EPA's estimates of emissions reductions.23 This study utilized the Fugitive Emissions Abatement Simulation Toolkit (FEAST) model that was developed by Stanford University, to simulate emissions reductions achieved at the various monitoring frequencies. The study used information from the EPA's model plant analysis for the 2016 rule, including the site-level baseline emissions. Emissions reductions were estimated at 32% for annual monitoring, 54% for semiannual monitoring, and 70% for quarterly monitoring. This information suggests that the EPA's estimated reduction efficiencies for OGI at these monitoring frequencies are appropriate.

Finally, based on comments asserting the use of Method 21 effectiveness estimates based on the Synthetic Organic Chemicals Manufacturing Industry (SOCMI), we have updated the Method 21 effectiveness using information for the oil and gas industry. We used the same methodology used in 2016 to determine the Method 21 effectiveness but applied the average leak rates and emissions factors that are specific to the oil and gas industry.24,25 The revised analysis estimates emissions reductions when using Method 21 to be 40% for annual monitoring, 54% for semiannual monitoring, and 67% for quarterly monitoring. However, we note that Method 21 is not effective for all fugitive emissions components, such as controlled storage vessels, and we believe that OGI will detect large emissions that Method 21 would otherwise not detect.

In conclusion, we performed detailed analyses of the CAPP studies, the FEAST model results, and the updated Method 21 estimates. After these analyses, we conclude that the estimated effectiveness percentages of OGI monitoring at various frequencies are appropriate and that they do not over (or under) estimate the emission reduction that will be achieved.

The second uncertainty identified in the October 15, 2018, proposal relates to the occurrence rate of fugitive emissions, or the percentage of components identified with fugitive emissions during each survey. This information is key in assessing the cost of monitoring, as the higher this percentage is, the more resources owners and operators must expend to repair the leaks. In our previous analysis, it was assumed that each monitoring survey would identify 4 components with fugitive emissions. That is, when a site is monitored annually, we estimated 4 total components leaking for that year, but if that same site were monitored semiannually, we estimated 8 total components leaking for that year. While more frequent monitoring does have a different occurrence rate, the different between semiannual and annual is not 100%. In our analysis of Method 21 effectiveness (assuming a 500-ppm repair threshold), the leak occurrence rates for semiannual and annual monitoring are 3.65% and 4.72%, respectively. That means that during an annual Method 21 survey, you would expect to find 4.72% of the components with fugitive emissions, whereas for each semiannual Method 21 survey you would find 3.65% of the components with fugitive emissions. For purposes of updating our model plant analysis where OGI is the BSER, we did not apply these specific occurrence rates, but instead evaluated the annual compliance report information for the 2017 and 2018 reporting years. For this analysis we pulled reports from CEDRI that included fugitive emissions information for 2,800 well sites. We then determined the average number of fugitive components reported as leaking from these reports. An estimate of 3 components per annual survey and 2 components per semiannual and quarterly survey were applied to the model plant analysis. These values are similar to those provided by several commenters.26 For gathering and boosting compressor stations, we examined the information provided by the GPA Midstream, and determined that on average 11 components were identified as leaking during the year.27 We applied this value for all monitoring frequencies because the number of reported leaks varied widely in the dataset. For transmission and storage compressor stations, we applied the average number of components leaking per year per compressor station as reported to the EPA's GHG Reporting Program (GHGRP). There were approximately 24 leaks per transmission compressor station and approximately 60 leaks per storage compressor station. Similar to our treatment for gathering and boosting compressor stations, we assumed that these were the total number of leaks would be repaired annually regardless of monitoring frequency. This information was applied to the updated model plants for the existing requirements and to the analysis based on this final rule. Therefore, no additional cost reductions are realized for the individual monitoring frequencies based on these updates to the analysis and we no longer consider this to raise uncertainties with the analysis.

The final uncertainty raised in the October 15, 2018, proposal was the initial percentage of components identified with fugitive emissions. This is important as this percentage is a key element in determining the baseline emissions prior to any fugitive emissions monitoring program. The commenters stated their belief that the emissions factor used to estimate the baseline emissions was calculated using a percentage of leaking components that was too high, thus biasing the baseline emissions (and the resulting emission reductions) high.

One commenter pointed out that the 1.18% initial leakage percentage cited by the EPA in the October 15, 2018, proposal preamble was not the actual estimate used. The commenter is correct on this point. The uncontrolled emissions factors for non-thief hatch fugitive emission components the EPA used to estimate model plant emissions for the October 15, 2018, reconsideration proposal are based on Table 2-4 of the Protocol for Equipment Leak Emission Estimates ("Protocol Document").28 The leak fractions that are inherent in these emissions factors are not specifically stated in the Protocol Document, but the commenter performed a back-calculation of the fraction of leaking components using Table 5-7 of the Protocol Document and the weighted leak fraction for all components using the number of each component per model plant. That result, which the EPA agrees with, shows that the percentage of leaking components found at an initial survey was 2.5% when using Method 21 and a leak definition of 500 ppm and 1.65% when using Method 21 and a leak definition of 10,000 ppm. The commenter provided leak monitoring data that indicated an overall leak percentage of 0.4% components detected with fugitive emissions out of all components monitored when using OGI. The commenter then compared this to the 2.5% and 1.65% leaking components inherent in the emissions factors from the EPA Protocol Document. More discussion of this information, as well as the EPA's analysis, can be found in a separate technical memorandum.29 This information suggests that the EPA's emissions factors (based on the 10,000 ppm leak threshold) could be over 4 times too high. The Protocol Document emissions factors were based on leak rates detected using Method 21, while the commenter's leak rates are based on OGI. Following promulgation of the 2016 NSPS OOOOa, Stanford University published a study that evaluated the effectiveness of the OGI monitoring requirements in the 2016 NSPS OOOOa.30 In that study they the City of Fort Worth Study (FW Study), which surveyed and quantified fugitive emissions at production sites using both OGI and Method 21. When using Method 21, 1.07% of the components were identified as leaking, whereas OGI only identified 0.175%.31 The Stanford study suggests there is evidence that there is an order of magnitude difference in the percentage of components identified leaking with OGI (0.1%-0.3%) compared to Method 21 (1%-2%). This information supports the estimates that the EPA has used related to the initial percentage of components leaking prior to the initiation of a fugitive emissions monitoring program.

Another industry commenter provided leak rate information for their operations in the San Joaquin Valley that showed leak rates considerably lower than the previously discussed leak rate provided by the above industry commenter. Specifically, these rates, which were based on Method 21 monitoring, showed leak rates of around 0.04%. While the EPA applauds this company for their excellent record in reducing emissions from fugitive components at oil well sites, this information represents a very mature program. Therefore, it is not representative for assessing the baseline situation prior to the initiation of any program. In fact, this data would suggest that the EPA's assumptions regarding the number of leaking components that need to be repaired (see the discussion above regarding the second uncertainty) likely significantly overestimates the cost of performing the repairs.

In addition to the industry commenters, environmental commenters provided information related to fugitive emissions that is relevant to the determination of baseline fugitive emissions from oil and natural gas well sites. These commenters included reference to either individual studies in their comments that reported site-level measurement data from more than 1,000 sites in eight basins. In these studies, the measurements included emissions from all sources (vented and fugitive) at the well sites. In order to obtain an estimate of the fugitive emissions, the commenter assumed that roughly 50% of the total emissions were fugitive emissions. The EPA's analysis of this information32 showed that fugitive emissions could be as much as four times higher than the EPA model plant emission estimates (depending on the type of well site). While there is considerable uncertainty associated with the assumption that 50% of the total site emissions are fugitive emissions, this information suggests that the EPA's estimates of the baseline emissions, and thus the initial leak rates, could be biased low.

After consideration of the comments received, and analysis of the data submitted, we have concluded that the emissions factors from the 1995 Protocol Document used previously for the baseline fugitive emission estimates, which are dependent on the initial leak rate prior to the implementation of any fugitive monitoring program, are appropriate. Therefore, the EPA did not adjust the baseline emissions factors in the updated BSER analysis for this final rule.

As discussed above, there were 3 areas of concern identified in the October 15, 2018, proposal: (1) the effectiveness of OGI at the various frequencies, (2) the occurrence rate for each survey, and (3) the initial percentage of components identified with fugitive emissions. Data was provided by several commenters and evaluated for this final rule. We were concerned that we might have overestimated the emission reductions from the current monitoring frequencies in the rule due to these three areas of certainties. We have made the above-mentioned revisions to the model plant analysis and no longer consider these to be areas of concern or uncertainty with the analysis.

We also received information from commenters that suggested additional updates to the model plants were necessary, beyond those already discussed. These included the major equipment counts and survey costs. The following discussion will address all other updates by specific model plant type (e.g., well site, low production well site (those producing at or below 15 barrels of oil equivalent (boe) per day), and compressor station).

The model plant analysis for well sites exceeding 15 boe per day averaged over the first 30 days of production was updated based on updates to the activity counts in the 2017 GHG Inventory (GHGI). While the activity factors by equipment type changed slightly, once rounded to the nearest integer, there was no change in the major equipment counts. We also maintained the assumption of 1 controlled storage vessel subject to the fugitive emissions requirements that was proposed based on our review of the number of well sites reported as subject to the fugitive emissions requirements and the estimated number of new storage vessels that would not be subject to control in the rule. Another element we evaluated is the cost of performing each survey. In the October 15,2018, proposal we maintained the assumed flat contractor fee of $600 per survey. However, information from commenters suggested this may be an overestimate of survey costs if an hourly rate were used. To examine this comment, we analyzed the CEDRI reports, and evaluated the survey times that were reported. Based on this information, we estimated it takes operators 3.4 hours to complete a survey at a well site, including the travel time to and from the well site. This is based on an average survey time of approximately 1.4 hours. The travel time considers travel between sites and the shared travel of mobilizing a monitoring operator. We applied an hourly rate of $134 based on the Regulatory Analysis performed by the Colorado Department of Public Health and Environment in support of Colorado's Regulation 7.33 We believe this more accurately reflects the costs of performing the survey than the previously assumed flat rate of $600.

The low production well site model plants were updated after further review of the FW Study, updates to the GHGI, and based on comments received. First, the counts of wellheads, separators, meters/piping, and dehydrators were recalculated after removing well sites that listed no production on the day prior to emissions measurements during the FW Study. This resulted in a decrease in the number of separators and meters/piping for the low production gas well pad. The scaling factors were also updated based on these revisions and applied to low production oil well pads and low production associated gas well pads. Further discussion on these changes are in the TSD. Like well sites, we maintained the estimate of 1 controlled storage vessel per low production well site. One commenter provided some preliminary information regarding component counts, specific to valves and storage vessels, but also stated in their comments that the information was not representative.34 Therefore, as discussed in the TSD, it was not appropriate to revise the model plants using information the commenter provided. We also performed an analysis of the survey time and found that on average, the surveys for low production well sites were approximately 30 minutes. After accounting for travel time, we estimate that each survey of a low production well site takes 2.4 hours. We applied the same hourly rate of $134 to estimate the total cost of each survey.

Information of average equipment counts were provided by GPA Midstream for gathering and boosting compressor stations.35 We updated the model plant estimate to use this information. Specifically, we revised the estimated number of separators from 11 to 5, meter/piping from 7 to 6, gathering compressors from 5 to 3, in-line heaters from 7 to 1, and dehydrators from 5 to 1. We maintained the cost for the survey of $2,300 because the commenter indicated this was appropriate based on implementation of the rule.

One commenter stated that the EPA should utilize the measured emissions information reported through the GHGRP instead of the 1995 GRI/EPA study that was used in the 2016 rule and maintained in the October 15, 2018, proposal.36 This commenter asserted that the measured emissions are more reflective of present operations at transmission and storage compressor stations. While we maintain that the fugitive emissions components reported through the GHGRP are not inclusive of all fugitive emissions components subject to monitoring and repair in this rule, we performed a sensitivity analysis to determine the impact of such a change. We found that the average compressor station emissions from fugitive emission components as determined from data reported to the GHGRP (which includes equipment leaks and certain leaks that are reported as compressor emissions) are greater than the emissions originally estimated using the 1996 GRI/EPA study data.37

With the above revisions incorporated, we reexamined the costs and emission reductions for various monitoring frequencies to determine the updated cost of control. Consistent with the October 15, 2018, proposal, there is sufficient evidence that low production well sites are different and warrant a separate evaluation of the cost of control. The TSD presents the cost of control for annual, semiannual, and quarterly monitoring frequencies for well sites and compressor stations, and biennial, annual, and semiannual monitoring frequencies for low production well sites.

As shown in the TSD, for annual monitoring of well sites, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,700 per ton of methane reduced, and $1,501 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $6,114 per ton of VOC reduced, and $5,401 per ton of VOC reduced if savings of the natural gas recovered is considered.38 These costs reflect the total cost-effectiveness of implementing an annual monitoring program where no program exists. It is equally important to evaluate the additional cost of control when increasing the monitoring frequency. For semiannual monitoring of well sites, 18,242 additional tons of methane and 5,071 additional tons of VOC can be reduced beyond an annual monitoring program. These additional reductions are achieved at a cost of $879 per additional ton of methane reduced, and $681 per additional ton of methane if the savings of the natural gas is considered. The additional VOC reductions are achieved at a cost of $3,163 per additional ton of VOC reduced, and $2,450 per additional ton of VOC reduced if savings of the natural gas is considered. These values are deemed cost-effective, therefore, BSER for the collection of fugitive emissions components located at a well site (with production greater than 15 boe per day) remains semiannual monitoring.39

For biennial monitoring of low production well sites (i.e., well sites with average production less than 15 boe per day averaged over the first 30 days of production), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,583 per ton of methane reduced, and $1,385 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $5,695 per ton of VOC reduced, and $4,982 per ton of VOC reduced if savings of the natural gas recovered is considered. These costs reflect the total cost-effectiveness of implementing a biennial monitoring program where no program exists. It is equally important to evaluate the additional cost of control when increasing the monitoring frequency. For semiannual monitoring of low production well sites, 5,820 additional tons of methane and 1,618 additional tons of VOC can be reduced beyond a biennial monitoring program. These additional reductions are achieved at a cost of $1,611 per additional ton of methane reduced, and $1,413 per additional ton of methane if the savings of the natural gas is considered. The additional VOC reductions are achieved at a cost of $5,797 per additional ton of VOC reduced, and $5,084 per additional ton of VOC reduced if savings of the natural gas is considered. These values are deemed cost-effective, therefore, BSER for the collection of fugitive emissions components located at a low production well site remains semiannual monitoring.40

For annual monitoring of compressor stations, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $704 per ton of methane reduced, and $572 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,606 per ton of VOC reduced, and $2,927 per ton of VOC reduced if savings of the natural gas recovered is considered. These costs reflect the total cost-effectiveness of implementing an annual monitoring program where no program exists. It is equally important to evaluate the additional cost of control when increasing the monitoring frequency. For semiannual monitoring of compressor stations, 5,265 additional tons of methane and 1,028 additional tons of VOC can be reduced beyond an annual monitoring program. These additional reductions are achieved at a cost of $549 per additional ton of methane reduced, and $416 per additional ton of methane if the savings of the natural gas is considered. The additional VOC reductions are achieved at a cost of $2,811 per additional ton of VOC reduced, and $2,132 per additional ton of VOC reduced if savings of the natural gas is considered. For quarterly monitoring of compressor stations, 5,265 additional tons of methane and 1,028 additional tons of VOC can be reduced beyond a semiannual monitoring program. These additional reductions are achieved at a cost of $1,095 per additional ton of methane reduced, and $962 per additional ton of methane if the savings of the natural gas is considered. The additional VOC reductions are achieved at a cost of $5,607 per additional ton of VOC reduced, and $4,928 per additional ton of VOC reduced if savings of the natural gas is considered. These values are deemed cost-effective, therefore, BSER for the collection of fugitive emissions components located at a compressor station remains quarterly monitoring.41

C. AMEL

The existing rule contains provisions for requesting an AMEL for specific work practice standards covering well completions, reciprocating compressors, and the collection of fugitive emissions components at well sites and compressor stations. The provision included in the existing rule could be used for emerging technologies or existing state programs. This section describes changes, based on information provided in public comments, to the AMEL provisions.

1. Incorporation of Emerging Technologies

The EPA continues to recognize that new technologies are expected to enter the market in the near future that could locate the source of fugitive emissions sooner and at lower costs than the current technology. While the EPA established a foundation for approving the use of these emerging technologies, we proposed specific areas to help streamline the process. Specifically, we proposed to allow owners and operators to apply for an AMEL on their own or in conjunction with manufacturers or vendors and trade associations. We also proposed to allow the use of test data, modeling analyses, and other documentation to support field test data, provided seasonal variations were accounted for in the analyses. While we received many supportive comments on these specific proposed amendments, we also received comments that assert the application process is too restrictive and burdensome to promote innovation.

First, the commenters stated that applications seeking approval of an alternative should be accepted by the EPA from manufacturers and vendors independently of owners and operators. We have reviewed the information provided by the commenters and agree that it is appropriate in the context of the revisions to 40 CFR 60.5398a to remove language that previously indicated who the Administrator would consider applications under that section from. While the EPA agrees that any person can submit an application for an AMEL under this provision, the final rule still includes the criteria that the EPA expects within each application in order for the EPA to make a determination of equivalency and thus be able to approve an alternative. The EPA expects that applications for these AMEL will need to include site-specific information to demonstrate equivalent emissions reductions, as well as site-specific procedures for ensuring continuous compliance of the emissions reductions to be demonstrated as equivalent.

Next, the commenters generally supported the proposed amendment to allow the use of test data, modeling analyses, and other documentation to support field test data. In addition to their support of these supplemental data, commenters also requested that the EPA consider information collected during testing at controlled testing facilities be considered in lieu of site-specific field testing. The EPA considered whether it would be appropriate to allow this information and has some concerns related to the representativeness of the information when compared to actual operating sites. For example, we are aware of one controlled testing facility located in the US, the Methane Emissions Technology Evaluation Center (METEC) located in Fort Collins, Colorado.42 That facility is equipped with several different configurations of well pads using equipment that was donated from the oil and natural gas industry. These test well pads do not produce or process field gas; in fact, none of the equipment that is onsite is in contact with field gas. Instead, METEC utilizes compressed natural gas that is transported from offsite in order to create controlled leaks. In establishing controlled leaks, METEC uses tubing with leak points hear typical leak interfaces to simulate a leak, however, these releases are not operated at pressure or temperatures that are typically encountered at an operating well site. While we agree that testing at a controlled testing facility such as the METEC site can be helpful to understanding how a technology may perform and the information gathered from such controlled test sites can be useful in supplementing other data, it is inappropriate to rely solely on the information collected at these types of facilities as being representative of how the technology would perform at an operating well site or compressor station. At this time, the EPA does not believe that it can determine the efficacy of a measurement technology where demonstrations take place only under controlled conditions. By extension, the EPA would be unable to determine the validity of whether an alternative indeed achieves equivalent emissions reductions if only presented with data from testing at a controlled testing facility. Therefore, we are finalizing amendments that require field test data but that allow the use of test data, modeling analyses, data collected at controlled testing facilities, and other documentation to support and supplement field test data.

Next, we solicited comment on whether groups of sites within a specific area that are operated by the same operator could be grouped under a single AMEL. We received comments that discussed broad application of alternatives in two distinct ways: (1) allowing the aggregation of emission sources beyond the individual site in order to demonstrate equivalent emission reductions, and (2) allowing the use of approved AMELs at future sites that are designed and operated under the conditions specified in the approved AMEL. We evaluated both types of broad approval options raised in the comments by considering definitions in the existing rule and our understanding of the AMEL provisions of section 111(h)(3) of the CAA.

In the first instance, we evaluated whether it is appropriate to allow the aggregation of emission sources beyond the individual site when evaluating equivalency of an alternative. Specifically, we considered whether an applicant for an AMEL related to fugitive emissions monitoring could aggregate the total fugitive emissions across multiple sites within a specific geographic area, such as a basin, in order to demonstrate the requested AMEL would achieve at least equivalent emission reductions as the NSPS required fugitive emissions monitoring and repair at an individual site. The work practice standards for the collection of fugitive emissions components at a well site or at a compressor station were established pursuant to section 111(h) of the CAA, which is what allows an opportunity for an AMEL. In accordance with paragraph 111(h)(3) of the CAA, a source may use an approved AMEL for purposes of compliance with the establish work practice. The commenters stated the generic use of the word "source" allows aggregation of fugitive emissions components amongst multiple sites and is not limited to single sites as we had proposed. The EPA does not agree that examining the aggregate of fugitive emissions across multiple sites is a viable method to determine equivalency with the NSPS provided the current definitions in the existing rule. The existing rule, and this final rule, define the "source" that is subject to the work practice standards for fugitive emissions as the "collection of fugitive emissions components at a well site" and the "collection of fugitive emissions components at a compressor station" in 40 CFR 60.5365a(i) and (j). These terms specify single site applicability for the work practice standard. Therefore, based on this regulatory scheme established in the NSPS it is the EPA's determination that a demonstration of equivalent emission reductions must be provided based on the fugitive emissions at a single site, and not an aggregation of emissions across multiple well sites, compressor stations, or a combination of these two site types. This is not to say that the EPA is foreclosing the possibility of ever utilizing any work practice standard that aggregates emissions across multiple sites, but just that such an approach is not appropriate to use now when evaluating alternatives provided the current manner in which the existing rule's work practice standard applies to individual sites.

The second point raised by commenters was that site-specific approvals (i.e., AMELs that list specific well sites or compressor stations) would cause unnecessary burden as new sites with the same owner or operator, similar equipment, operating conditions, and in the same geographic area (e.g., basin) are constructed. According to commenters, this unnecessary burden results from the need for the owner or operator to apply for an AMEL for each of these sites in the future, even without any changes to the previously approved AMEL for similar sites. We agree with the commenters that it is possible that AMELs could, where appropriate, be approved for future use at sites not included in the original application. However, due to the variability of this sector as well as the wide-ranging array of technologies currently being pursued for development, we do not believe it is appropriate for us to amend the language within the rule to allow for the future use of an approved AMEL without first understanding what is being requested. Put another way, the EPA believes that it is possible for an AMEL application to demonstrate that broad applicability of an alternative is appropriate under certain conditions or criteria, but the EPA will need to evaluate whether such demonstration is adequate during the AMEL process. Alternatively, if a technology can be shown to have broad applicability across the source category, the EPA may find it more appropriate to undertake a rulemaking process to change NSPS OOOOa to allow for widespread use of the technology. As always, each application for an alternative will be reviewed individually to determine if the application has demonstrated at least equivalent emission reductions as the work practice standard the alternative would replace. If the applicant believes that it is appropriate to apply the alternative to more sites than those listed in the application because the proposed alternative can achieve equivalency for other sites, then the applicant should state this intent and make this demonstration to the EPA within the application. If provided sufficient information, explanation, justification, and documentation, the EPA may evaluate under what defined conditions, if any, it is appropriate to allow future use of the alternative once approved either via the AMEL process or the rulemaking process. Due to concerns that procedures for a specific technology may need to be adjusted based on site-specific conditions, we are not amending the rule to allow for future use by any site of any previously-approved AMEL and will instead determine the applicability of a specific AMEL in the AMEL review process.

In summary, we are finalizing amendments to the application requirements for an AMEL in 40 CFR 60.5398a. We are allowing applications from any person. Further, we are allowing the use of supplemental data, such as test data, data collected at controlled testing facilities, modeling analyses, and other relevant documentation, to support field data that is collected to demonstrate the emissions reductions achieved. While we are not amending the rule to specifically state that future use of an approved AMEL will be allowed, we are recognizing that it may be possible, where appropriate, to establish specific conditions under which an approved alternative may be applied at sites not specifically listed in the application.

2. Incorporation of State Fugitive Emissions Programs

To reduce duplicative burden to the industry related to the fugitive emissions requirements, the EPA proposed alternative fugitive emissions standards for well sites and compressor stations located in specific states. These alternative standards were proposed based on the EPA's review of the monitoring and repair requirements of the individual state fugitive emissions (or LDAR) requirements relevant to well sites and compressor stations. In the proposal, we stated that a well site or compressor station, located in the specified state, could elect to comply with the specified state program as an alternative to the monitoring, repair, and recordkeeping requirements in the NSPS. However, these sites would be required to monitor all fugitive emissions components, as defined in the NSPS, comply with the requirement to develop a monitoring plan, and report the information required by the NSPS.

Similar to the proposed amendments for incorporating emerging technologies, we received support for the proposed amendments for incorporating state programs. However, some commenters stated that the EPA should recognize the approved state programs as wholly equivalent, including all reporting and recordkeeping requirements. The commenters indicated that the EPA's equivalency determination leaves the regulated community in certain states subject to duplicative requirements. They added that complying with two different reporting and recordkeeping schemes for the same site is very burdensome and provided no environmental benefit.

For the October 15, 2018, proposal, we evaluated 14 existing state programs for comparable or equivalent standards related to the fugitive emissions requirements in 40 CFR 60.5397a. That evaluation included a qualitative comparison of the fugitive emissions components covered by the state programs, monitoring instruments, leak or fugitive emissions definitions, monitoring frequencies, repair requirements, and recordkeeping requirements to the requirements of the NSPS.43 However, at the time of the October 15, 2018, proposal, the EPA had not evaluated the reporting requirements of the 14 individual state programs. We have completed that evaluation for this final rule on the states that were proposed with alternative standards and the results are discussed in more detail for the reporting and recordkeeping in Section VI.C.2 of this preamble. We also updated the overall analysis of equivalency.44 Through this additional evaluation, we concluded the determination of equivalency of a program should not be affected by the recordkeeping and reporting requirements. It is inappropriate for the EPA to directly compare the recordkeeping and reporting requirements of the fugitive emissions requirements in the NSPS to the recordkeeping and reporting requirements of the individual state programs. This is because the recordkeeping and reporting requirements are determined based on compliance assurance with the standards that apply. The standards for the NSPS are not identical to the standards of the state program. Therefore, in performing this evaluation of reporting requirements in the individual state programs, we based our review on elements that the EPA deems essential for a demonstration of compliance with the alternative standard.

At a minimum, the EPA expects reports to include information that allows a demonstration of compliance at the individual site level. For three of the six states (California, Ohio, and Pennsylvania) where we are finalizing alternative standards, the required reports meet this requirement because reports are site-specific. Therefore, for these three states, a site electing to comply with the alternative standards is required to submit their state report as an attachment to the annual federal report required in 40 CFR 60.5420a(b), in lieu of the federal report, in the same format in which it was submitted to the state. For the other three states (Colorado, Texas, and Utah), a site electing to comply with the alternative standards is required to submit the information required in 40 CFR 60.5420a(b)(7). This distinction is made because we were unable to determine that the current state-level reporting requirements for sources in the states of Colorado, Texas, and Utah are sufficient to provide this level of site-specific detail.

In addition, we reviewed the recordkeeping requirements for these three states (Colorado, Texas, and Utah) and determined that the required information for the NSPS report is very similar to, if not the same as, the information required to be kept as records for these state programs, with one notable exception. The report for NSPS OOOOa requires the ambient temperature, sky conditions, and maximum wind speeds at the time of each survey. While we were unable to determine that this information is kept in the record for these states, recording and reporting this information presents minimal burden and all sites currently subject to the NSPS are already recording and reporting this information. Further, these sites are still required to have procedures in place, through their monitoring plans, that address these weather conditions. Given that it appears that all other required reporting elements under the NSPS are in the records required by the states, it is the EPA's conclusion that there is no duplicative burden associated with compliance with these alternative standards. We believe that adoption of these alternative standards will further reduce the burden of the fugitive emissions standards on the industry from this rule, because the sites are incurring minimal burden associated with reporting information to the EPA under the NSPS that is already required by the state for recordkeeping. No additional recordkeeping beyond that required by the alternative standard is necessary, except as noted above for weather conditions during the survey.

One commenter expressed concern over the proposed state equivalency determinations and noted that several of the programs evaluated have specific applicability thresholds where the standards only apply to a subset of sources, whereas the NSPS applies to all new, modified, or reconstructed sources.45 The commenter indicated that, based on their analysis, only 34% of the wells covered by the requirements in NSPS OOOOa in the six states with alternative fugitive standards would be subject to those alternative standards. We agree that applicability thresholds are different for these programs, but we do not agree that additional regulatory text is necessary to address this concern. The purpose of the alternative standards is to allow any site that is subject to this final rule and located in a state for which an alternative standard is finalized the option to comply with the monitoring, repair, recordkeeping, and reporting requirements of the alternative standard instead of the fugitive emissions requirements of this rule. Plainly, if the site elects to comply with an alternative standard, they must monitor all fugitive emissions components as defined in 40 CFR 60.5430a, develop and comply with a monitoring plan as required in 40 CFR 60.5397a(c) and (d), monitor all fugitive emissions components at the frequency specified by the alternative standard, repair all detected emissions within the timeframe specified by the alternative standard, maintain the records required by the alternative standard, and, where appropriate, report the required information of the alternative standard electronically to the EPA. While the commenter's concern was partially related to a site assuming that monitoring is not required because that site does not meet the monitoring threshold for the state program, the site is not in compliance with the alternative standard, or the NSPS, if they do not monitor for fugitive emissions. Put another way, the regulatory thresholds included in state programs that limit or reduce monitoring and repair requirements do not apply to sources subject to the NSPS. Where appropriate, we have amended the proposed text to clearly state the requirements of the alternative standard. This includes adding a statement for sites located in Ohio and Texas that monitoring frequencies must be at least semiannual (for well sites) and quarterly (for compressor stations) and skip periods may not be applied. We have also amended the proposed 40 CFR 60.5399a to include alternative standards for compressor stations located in Texas based on further review of those requirements. More discussion of this comment and our response is provided in Section VI.C.2 of this preamble.

In summary, we are finalizing a new section to address alternative standards for sites located in specific states at 40 CFR 60.5399a. In that section we are finalizing procedures for application from any interested person, including, but not limited to, individuals, corporations, partnerships, associations, states, or municipalities. These applications must include the specified information to allow the EPA to determine if the program achieves equivalent emissions reductions as the fugitive emissions requirements in the NSPS. We are also finalizing alternative standards for well sites and compressor stations located in California, Colorado, Ohio, Pennsylvania, and Texas, and alternative standards for well sites in Utah. These alternative standards require the owner or operator of the site to monitor all fugitive emissions components as defined in 40 CFR 60.5430a, develop and comply with a monitoring plan as required in 40 CFR 60.5397a(c) and (d), monitor all fugitive emissions components at the frequency specified by the alternative standard, repair all detected emissions within the timeframe specified by the alternative standard, maintain the records required by the alternative standard, and report the required information of the alternative standard electronically to the EPA.

VI. Summary of Significant Comments and Responses

This section summarizes the significant comments on the proposed amendments and our response to those comments. Additional comments and responses are summarized in the Response to Comments (RTC) document available in the docket.

A. Major Comments Concerning Storage Vessels

There were numerous comments received on the proposed amendments to the definition of "maximum average daily throughput," which is key in the determination of storage vessel affected facility applicability. Many of the comments received were related to manifolded storage vessel systems. The EPA considered those comments and is finalizing changes to the rule to address storage vessel applicability related to manifolded storage vessel systems. Specifically, the final rule subcategorizes storage vessels based on two distinct types: (1) an individual storage vessel that is not designed and operated as a manifolded storage vessel system ("Type 1"), and (2) a storage vessel that is part of a manifolded storage vessels system that meets specific design and operational requirements ("Type 2"). Type 2 storage vessels are not subject to the cover, closed vent system and control requirements of the rule, and instead are subject to the fugitive requirements in 40 CFR 60.5397a. These comments and the rationale for our final actions were previously discussed in detail in Section V.A of this preamble. More detailed comments regarding manifolded storage vessel system applicability considerations are provided in the Response to Comment document for this action (see Section 6).46

In addition to these manifolded storage vessel system comments, the EPA also received other comments related to the storage vessel requirements. Below are discussions related to three of these topics: (1) legally and practically enforceable limits, (2) calculation of maximum average daily throughput based on days of production, and (3) determination of maximum average daily throughput for storage vessels at compressor stations and natural gas processing plants.

Comment: Commenters were concerned about the EPA's proposal to put additional parameters on what constitutes a "legally and practically" enforceable limit. One commenter noted the EPA suggests additional criteria on what constitutes a legally and practically enforceable limit. Specifically, the commenter notes that the EPA proposed that limits meet "certain enforceability criteria" which were described in the preamble to the proposed rule. One commenter disagreed that the EPA's enforceability criteria requires the heightened standard proposed by the EPA. They indicated that the proposed amendments: (1) conflict with prior EPA statements during NSPS OOOO rulemakings; (2) conflict with traditional EPA practice to defer to states to determine appropriate mechanisms for limiting potential to emit (PTE); (3) raise concerns about how this new interpretation/approach would apply in the Title V and New Source Review ("NSR")/Prevention of Significant Deterioration ("PSD") context where operators are relying on the same control requirements to limit their PTE; (4) raise significant concerns about retroactive application; and (5) ignore that the requirements for fugitive components under NSPS OOOOa are not tied to storage tank applicability and apply regardless of whether a storage tank is an affected facility under the rule. The commenter also cited the EPA's "enforceability criteria" guidance, which was first introduced in 1995, and how the EPA's proposed additional criteria are not consistent with the 1995 Guidance. Further, commenters noted that relying on the EPA's consistent interpretation of "legally and practically enforceable limits" since 1995, operators around the country rationally interpreted both NSPS OOOO and NSPS OOOOa to allow them to account for state regulations and permit conditions requiring the control of storage tanks when calculating PTE for purposes of applicability to those subparts. The commenter is concerned that the EPA's new approach in the proposed reconsideration amendments not only conflicts with its traditional and consistent practice, it also threatens to subject existing sources to performance standards without sufficient notice.

The commenter expressed belief that the EPA's suggestion that existing state regulatory programs and permit conditions no longer meet the definition of "legally and practically enforceable" also casts uncertainty on other CAA programs. The commenter asserts that operators currently rely on the same regulations and permit conditions used to restrict PTE for NSPS OOOO and NSPS OOOOa to remain a synthetic minor under the EPA's Title V and NSR/PSD programs and the EPA's proposal causes confusion and casts doubt on thousands of permits under these programs. Therefore, the commenters suggested that the EPA remove its proposal to impose additional parameters on enforceable limits under NSPS OOOOa and, consistent with longstanding practice, continue to defer to states to determine which of their programs satisfy the standard.

Response: The EPA did not intend to place additional parameters on what would constitute a legally and practically enforceable limit, rather to provide helpful discussion in the context of the existing substantial body of EPA guidance and administrative decisions relating to potential emissions and emissions limits. Limits that meet certain enforceability criteria may be used to restrict a source's potential emissions, and the permit or requirement must include sufficient terms and conditions such that the source cannot lawfully exceed the limit. For additional information and a summary of the EPA's position on establishing legally and practically enforceable limits on potential emissions, see In the Matter of Yuhuang Chemical Inc. Methanol Plant St. James Parish, Louisiana, Order on Petition No. VI-2015-03 (August 31, 2016) at 13-15. While the EPA did not add language to the final rule, the EPA continues to believe that the mentioned elements are important.

Comment: Commenters noted that EPA's proposed approach that "production to a single storage vessel must be averaged over the number of days production was actually sent to that storage vessel, rather than over the entire 30 days" ignores the fact that the same well production will be routed to different tanks in the battery throughout the 30-day period. The commenters asserted that averaging daily throughput for each individual tank based only on the days the tank actually receives production during the thirty-day evaluation period would over estimate the total amount of production that each tank could receive over a thirty-day window, and that compounded across multiple tanks and extrapolated across an entire year, this approach would significantly over estimate the volume of flow to the tanks as a whole. The commenters also

stated that the EPA's proposed approach fails to account for the fact that maximum well production has a limit based on what the wells can produce. However, one commenter agreed that owners and operators should not include days where the storage vessel does not receive production when determining storage vessel applicability.

Response: The concerns raised by the commenters, related to the proposed requirement that VOC emissions be calculated based on the number of days production was actually sent to that storage vessel during the first 30 days of production, were focused on situations where the storage vessel was part of a manifolded tank system. As discussed above and in Section V.A, the final rule subcategorizes certain storage vessels in manifolded systems (i.e., Type 2 tanks) and the applicability calculation does not include a determination of the potential for VOC emissions, so the provision regarding emission calculation only when production was sent to the storage vessel is not germane to Type 2 tanks. The EPA continues to believe this is important for other storage vessel configurations (Type 1) and have retained this requirement in the final rule.

Comment: One commenter recommended that the EPA revise and clarify the determination of maximum average daily throughput for storage vessels at well sites versus those at compressor stations and natural gas processing plants. The commenter noted that downstream facilities may not experience the same peak in production during the first 30-days of production seen at well sites. The commenter indicated that owners or operators may underestimate potential emissions based on the first 30 days. The commenter requested that the EPA clarify the time period to make an applicability determination as well as the time period to demonstrate initial compliance for storage vessels at facilities located downstream of well sites. Specifically, the commenter recommended that for midstream and downstream facilities the maximum projected throughput and corresponding VOC emissions for storage vessels requested in permit applications, and, once verified by the permitting authority, incorporated into permits as throughput and VOC limitations, be utilized to determine the applicability of NSPS OOOOa prior to facility startup. The commenter noted that throughput and emission limitations identified in permit applications should be a reasonable estimation of the maximum emissions expected for the condensate storage vessels at midstream and downstream facilities, regardless of how the storage vessels are operated within the first 30 days of startup.

Similarly, another commenter believed that the EPA should adjust how it calculates the maximum average daily throughput to determine potential emissions from storage vessels at gathering and boosting facilities, because given the nature of the operations, the throughput after the first 30 days is not representative, and, instead, facilities should be allowed to use generally accepted engineering models.

Response: The EPA agrees with the commenter that the standards for storage vessels appear to be written with a bias towards the operation of storage vessels located at well sites and that the determination of potential VOC emissions based on the first 30 days of throughput to a storage vessel located in the midstream and downstream operations may not reflect the true maximum throughput that will occur in the future. Our understanding now, based on the information provided by the commenters and subsequent conversations,47 is that these midstream and downstream storage vessels would continue to see an increase in throughput as additional upstream well sites begin sending fluids to these compressor stations and onshore natural gas processing plants. Further, the EPA understands that at transmission and storage compressor stations, the potential production of condensate is low because the gas has already been processed. Thus, these storage vessels are typically single storage vessels that are uncontrolled and permitted to maintain emissions below 6 tpy. Given that the 30-day production throughput calculation is not reflective of potential VOC emissions from midstream and downstream storage vessels, and the EPA's understanding of the models used to project future production throughput, and thus potential emissions, the EPA is revising the applicability criteria for determining the potential VOC emissions for storage vessels located at compressor stations and onshore natural gas processing plants. Specifically, these storage vessels must determine the potential for VOC emissions within 30 days after startup of the compressor stations or onshore natural gas processing plant based on (1) requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local, or tribal authority or (2) generally accepted engineering models to project the maximum average daily throughput for the storage vessel.

B. Major Comments Concerning Fugitive Emissions at Well Sites and Compressor Stations

In Section V.B, we discuss the significant changes from the proposal to this final rule related to the fugitive emissions requirements for well sites and compressor stations. For those changes we include a summary of the major comments that impacted our decisions. In addition, we also discuss substantial comments on topics related to the fugitive requirements that did not result in the need for significant changes in this final rule. Specifically, the topics addressed in Section V.B include discussions of the public comments and our resulting considerations related to: (1) the burden of the fugitive monitoring reporting and recordkeeping requirements; (2) the percent emission reduction achieved by OGI programs; (3) the frequency of leaks found during periodic fugitive leak surveys; (4) the initial leak frequency of components; and (5) the costs of the survey. We also discuss our re-analysis of BSER after consideration of all these topics.

In addition to the comments related to these topics, we also received comments on other aspects related to the fugitive emissions requirements. A discussion of these comments and our responses to two of the topics, low production well sites and monitoring of compressors at compressor stations during the operating mode, are provided below. The RTC document included in the rulemaking docket for this action includes detailed comments and responses to all the issues discussed in Section V.B, those associated with low production well sites and monitoring of compressor stations during the operating mode, and other topics related to the fugitive emissions requirements.

A number of comments were received about low production well sites (i.e., well sites with average combined oil and natural gas production for the wells at the site less than 15 boe per day averaged over the first 30 days of production) and the EPA's proposed amendment to reduce the monitoring frequency to once every two years for these sites. The comments ranged from the suggestion that the EPA totally exclude monitoring for low production wells to opposition to the proposal to reduce the monitoring frequency from semiannual to biennial.

Comment: Some industry commenters disagree with the use of model plants that rely on component counts to analyze low production wells. They maintain that there are major differences in the equipment at low production well sites and that there are frequent changes to this equipment. They also point out that the pressure in the systems decreases as production declines, which reduces the potential for fugitive emissions.

Response: The EPA recognizes the wide variation in equipment, operating conditions, and geological aspects across the country at low production well sites. We also acknowledge that it is extremely difficult, if not impossible, to characterize and account for all these differences in model plants. However, the EPA rejects the notion that because of this complexity the EPA should abandon efforts to attempt to analyze the fugitive emissions for low production wells and the need for regulation. In fact, these basic challenges are also true for non-low production well sites and the EPA has used model plants to analyze emissions, controls, and the need for regulation for oil and natural gas wells for over 20 years. Further, the EPA solicited comment on alternative analyses that could be used, instead of the model plant analysis presented, and did not receive comments that would allow us to modify the analysis beyond the updates discussed in Section V.B of this preamble. As we stated in response to comments on the 2016 NSPS OOOOa,48 the impacts of the regulation must be evaluated when developing (or reconsidering) a NSPS. For the fugitive emissions requirements (and other affected facilities), we utilize model plants that apply currently available methods to estimate emissions from fugitive emissions components at well sites and compressor stations. We continue to conclude this model plant methodology is appropriate based on the currently available information.

With regard to the pressure in the system, we would point out that the emission factors used to estimate the fugitive emissions from oil and natural gas well sites (from the 1995 Protocol for Equipment Leak Emission Estimates) do not distinguish between different operating pressure levels. In addition, we also received comments related to the leak rates/emissions from components at oil and natural gas wells. While these comments expressed the opinion that the EPA's initial leak rates and emissions factors used to estimate baseline emissions were too high, this data did not include any information related to the relationship between leak rate and operating pressure. Therefore, we continue to believe that the emission factors used in our analysis are representative of typical operating pressures which would include the lower pressures at low production well sites.

Comment: Commenters provide specific comments, along with data, related to the low production model plants developed and analyzed for the October 15, 2018, proposal. One commenter conducted a brief survey of their member companies' gas well site operations in 13 states and provided low production site component counts. This commenter points out that the majority of emissions (around 80 percent) from the low production model plants are from valves and storage vessel thief hatches. Therefore, they only provided counts of these components that contribute most of the emissions, along with the number of wellheads. This commenter explained the data provided demonstrated fewer wellheads and valves than assumed in the October 15, 2018, proposal model plant for low production gas well sites. Further, this commenter asserted the difference in component counts would affect the overall emissions estimates, with fugitive emissions overestimated in the model plants proposed. Another commenter submitted information on component counts based on data from the Ohio Department of Natural Resources, Ohio EPA's own information, and 40 CFR part 98, subpart W default component counts. This commenter did not specify the type of well site (e.g., non-low or low production).

Response: While the commenter specifically stated that they did not consider the data from their member companies in 13 states to be fully representative of low production well sites nationwide, we reviewed the information and compared it to the low production model plants used for the October 15, 2018, proposal analysis. Specifically, we compared the weighted-average counts of the information provided to the EPA's gas well site low production model plant. The information provided by this commenter showed that the weighted-average number of storage vessels was approximately the same as the EPA model plant, the number of well heads was half (1 versus 2 in the EPA model plant), and the number of valves was just under 25 percent (23 versus 100 in the EPA model plant). If the model plant was modified with these adjusted component counts, the overall difference in emissions would be just over 50 percent. However, information on fugitive emissions provided by other commenters indicate that the EPA model plants underestimate fugitive emissions at low production gas well sites by around 30 percent. While the data provided by the Ohio commenter did not separate low production and non-low production well sites, the number of valves per site was almost double (180) those in the EPA's low production model plant (100).

After consideration of these comments which presented conflicting data regarding whether the EPA's model plant was overestimating, or underestimating, component counts at low production sites, we concluded that there was insufficient information presented to revise the low production model plant component counts based entirely on this information. However, as discussed above in Section V.B, we did conduct further review of the data originally used to develop the model plant parameters, as well as GHGI data. The results of that review resulted in a 35% decrease in the number of valves for the low production gas well site model plant, as well as decreases in the numbers of the other components. More detailed information on the analysis of the component count information submitted by commenters is contained in a technical memorandum.49

Comment: Commenters recommend that an additional provision be included in the final regulation to transition non-low production well sites to low production well sites as the production declines and thus reduce the required frequency of monitoring to biennial. Some of these commenters also provided detailed recommendations of how the production calculations could be performed. Several commenters also recommended changing the definition of a low production well site to be based on the U.S. Tax Code definition of stripper wells and the time period for calculating production.

Response: As noted in Section V.B, we updated our BSER analysis for the fugitive emission requirements as we considered appropriate based on information and suggestions from commenters. The results of this analysis indicate that semiannual monitoring of all fugitive emissions components at all well sites, including those with average combined oil and natural gas production less than 15 boe per day averaged over the first 30 days of production, is cost-effective. Therefore, there is no distinction in the final rule between low production well sites and non-low production well sites. For that reason, there is no need to address the suggestions made by these commenters regarding the transition or "off-ramp" to a different classification as production declines, or to address the definition of low production.

Comment: Commenters urge the EPA to use the Department of Energy (DOE) research program50 announced on October 23, 2018, to determine more accurate assessments of low production well emissions. The commenters assert that the DOE study provides the EPA the opportunity to collect direct emissions data on fugitive emissions at low production well sites. The commenters conclude that this data would allow the EPA a baseline that shows the distinctions between large wells and low production wells and the differences that may exist between types of wells and between production regions.

Response: The EPA is regularly updated on the DOE program and provides technical input on many projects. We made our decisions on the final rule based on the information available at the time, which includes many data sources that cover low production wells such as DrillingInfo, GHGRP, and other emission measurement studies. Data from the DOE-funded study on low production well are not currently available. When the DOE program is completed, the EPA will review the results and assess how that information may be incorporated into the EPA programs.

Comment: The EPA proposed a requirement that each compressor must be monitored at least once per calendar year when it is operating. The EPA solicited comment regarding the effect the compressor operating mode has on fugitive emissions and comment on a requirement to conduct monitoring only during times that are representative of operating conditions for the compressor station.

Several industry commenters oppose the EPA's proposal to require that each compressor be monitored while in operation (i.e., not in stand-by mode). The commenters believe that the requirement will have the unintended consequence of generating emissions solely to monitor a compressor in a specific mode. The requirement will also create unnecessary recordkeeping and scheduling complexity/burden, according to commenters. Requiring equipment to be monitored in a specific mode of operation will increase emissions if that equipment must change its operational status solely to fulfill that requirement. These commenters recommend that the EPA allow operators to conduct surveys with facility operations as they are found when the survey is conducted.

However, another commenter states that their data suggests that it is important to conduct monitoring on fully operating compressors to maximize the number of leaks detected. They state that beyond this data it is also simply common sense that as the ratio of pressurized to depressurized components increases so will the number of leaks detected (depressurized components do not leak). One of the problems is that operation modes vary seasonally at each compressor station and within each compressor station the operating modes of each unit can vary daily based on demand. The current quarterly compressor monitoring frequency creates a higher probability of conducting a survey where each compressor is monitored in a pressurized mode at least once per year. If the EPA moved to less frequent monitoring, the commenter recommended that there should be some condition to ensure that a reasonable effort is made to schedule the surveys during a time of peak operation.

Response: The EPA reviewed the input provided by the commenters. While we believe that the opportunity for fugitive emissions could be greater when the compressor is operating, we understand that requiring owners and operators to change the normal operating schedule could result in greater emissions than a potential leak. Therefore, the EPA agrees with commenters that the proposed requirement that each compressor must be monitored while in operation (i.e., not in stand-by mode) at least annually is not appropriate and the EPA is not finalizing this requirement. The EPA has specified in the final rule that the monitoring survey of fugitive emissions components at a compressor station must be conducted at least quarterly after the initial survey and subsequent quarterly monitoring surveys must be conducted at least 60 days apart. Therefore, as pointed out by the commenter, the likelihood that all four monitoring events will be when the compressor is not operating is relatively low.

However, the EPA does conclude that it is important that the operating mode during the monitoring survey be recorded. While we would not expect that owners or operators would modify their operating schedules to avoid monitoring when the compressor is operating, or that they would purposely schedule every monitoring event during shutdown periods, we believe that this record would provide information to the Agency to indicate if this were occurring. Further, this information will provide valuable points for future analyses on leak rates and operating modes. Therefore, the final rule requires that owners and operators keep a record of the operating mode of each compressor at the time of the monitoring survey.

C. Major Comments Concerning AMELs

1. Incorporation of Emerging Technologies

EPA received comments related to AMEL for emerging technologies on several topics. The comments received by EPA that resulted in significant rule changes are discussed in section V.C.1 of this preamble, along with our response and rationale for the changes. The specific topics were (1) who can submit an AMEL application, (2) what data can or must be included in an AMEL application, and (3) what broader applications of alternatives are permitted. Further details on comments related to the broader applications of AMEL technology, specifically on the issues of applying AMEL to multiple similar sites or to categories of sources, are provided below along with EPA's responses. Other comments, and more detailed comments covering the topics discussed in this preamble, related to the incorporation of emerging technologies can be found in the Response to Comment document available in the docket, along with EPA's responses.

Comment: Many commenters felt that the proposal to approve AMEL for only a specific site should be revised to apply more broadly to multiple sites, basin-wide, industry-wide, or even based on nation-wide efficacy. Commenters asserted that restricting AMEL approval to a specific site is inconsistent with the EPA's past practice for OGI, in which the EPA determined that OGI achieves emission reductions equivalent to EPA Method 21 for several industries and source categories in a single rulemaking. Some commenters fear that the site-specific approval process that includes Federal Register notice and comment requirements is so onerous that it will stifle innovation in new technology and another noted that its customers have indicated that they would not apply for an AMEL if approval is site-specific. Commenters pointed out that the site-specific approval process could create a crush of AMEL applications for hundreds or thousands of sites, but the applications would be limited to only the technologies previously-approved or most likely to be approved as AMEL.

In response to the EPA's concern that alternative technologies may need to be adjusted for site-specific conditions, such as gas compositions, allowable emissions or the landscape, several commenters suggested that the EPA could account for the factors affecting variability, such as the weather or landscaping, by imposing conditions for the use of the technology and/or require periodic instrument checks, calibration records or other actions to ensure equivalent emission reductions are achieved. They noted that the technology approval for OGI includes these types of parameters, such as minimum/maximum temperatures and distance requirements, and that alternative technologies designed to detect and measure methane in the atmosphere will do that, regardless of gas compositions. The commenters also noted that if there is concern about allowable emissions impacting the usability of a particular technology, that technology may only be approvable for use as an approach to direct inspection efforts, but this factor would not affect the ability for it to be approved for that use at multiple sites.

Response: The EPA does not seek to stifle innovation of emerging technologies and encourages interested parties to discuss possible alternatives with the Agency. However, the EPA disagrees that this final rule should be the vehicle used to make any determinations about any particular technology because the proposed rule did not evaluate any specific technology. The EPA also disagrees that this rule is inconsistent with the EPA's past practice for OGI in the Alternative Work Practice (AWP), in which the EPA allowed use of OGI as an alternative to Method 21 for several industries and source categories in a single rulemaking.51 The EPA notes that while the AMEL process provided for in CAA section 111(h)(3) contains elements similar to a rulemaking (such as notice and opportunity for public hearing), approval of an AMEL does not always require rulemaking. If a technology is developed that could be broadly applied to oil and gas sites as an alternative to what is required in NSPS OOOOa, it may be more appropriate to incorporate such a technology into the rule through a formal rulemaking process.

As discussed in Section V.C.1 of this preamble, the EPA agrees that in some circumstances it may be appropriate to apply an approved AMEL to multiple sites. If the applicant of an AMEL believes that it is appropriate to apply the alternative to more sites than those listed in the application, the applicant should make this demonstration within the application. Specifically, the applicant should provide sufficient information, including any specific conditions, procedures, or site characteristics under which the alternative must be applied to demonstrate equivalence with the emissions reductions that would be achieved under the requirements of the NSPS. If sufficiently demonstrated, the EPA may evaluate these defined conditions and any additional conditions, if any, under which it may be appropriate to allow future use of the alternative once approved either via the AMEL process or a rulemaking process. For example, the EPA may approve the use of a specific fugitive emissions detection technology that operates with the same performance under specific work practice requirements, environmental conditions, and site configurations and operations. In that example, the EPA may determine it is appropriate to approve the AMEL and define the specific parameters (e.g., environmental conditions, site configurations, and operations) within the approval to allow the use of that alternative at sites meeting those same conditions without the need for application to the EPA. However, each of these determinations would necessarily be made on a case-by-case basis provided the application contains all necessary information to make such a broad determination for applicability of the AMEL. Given that these determinations are made on facts and showings that are specific to each proposed alternative, the EPA has determined it is inappropriate to include language in the regulation that suggests the EPA would always evaluate and/or incorporate broad applicability of an approved alternative.

Comment: Several commenters stated that the EPA should approve technology AMEL for categories of sources under NSPS OOOOa. They remarked that there is nothing in the statute that requires the EPA to set source-specific AMELs, and the EPA's position that source-by-source applications and approvals for AMEL is necessary is incorrectly taken from a narrow reading of the language of CAA section 111(h)(3). The commenters stated that while the language of section 111(h)(3) provides that AMEL is permitted to be used "by the source" for purposes of compliance, the EPA's reading of this to disallow the granting of AMEL for use by multiple sources is inconsistent with the NSPS approach of developing standards for whole categories of sources.

Some commenters said that because an AMEL will serve as a replacement for a category-wide CAA section 111(h)(1) standard, a demonstration that an AMEL will achieve an emission reduction at least equivalent to a 111(h)(1) standard could be made on a category-wide basis and be applied to an entire source category. These commenters suggested that allowing for source category-wide AMEL determinations would be consistent with the overall structure of CAA section 111 and its focus on category-wide standards under sections 111(b) and 111(h)(1) and with the limitation prohibiting the EPA from imposing specific technological emission reduction requirements pursuant to section 111(b)(5).

These commenters further stated that the EPA's regulation implementing CAA section 112(h)(3) recognizes that the EPA is authorized to approve an AMEL for "source(s) or category(ies) of sources on which the alternative means will achieve equivalent emission reductions." They contended that given the similarities between the programs authorized under CAA section 111 and CAA section 112 and, particularly the similarity of sections 111(h)(3) and 112(h)(3), the EPA should adopt its policy of applying an AMEL to source categories for section 111(h)(3) in the same manner as it has done with respect to section 112(h)(3). They noted that in other rules, such as the visibility provisions that require the best available retrofit technology (BART), the EPA's rules allow the EPA and the states to authorize BART alternatives that can apply to groups of sources and that allow emission averaging across sources, even over wide regions, rather than imposing source-specific emission limits or source-specific alternatives to such limits. The commenters state that if alternatives to emission limits (or work practice standards) for groups of sources under these provisions are permissible despite the continued references to the term "source" in the statutory language, then a source category-wide AMEL is surely permissible under section 111(h)(3).

Response: The EPA disagrees with the interpretation of section 111(h)(3) of the CAA that is presented by the commenters. Specifically, the EPA has determined that the commenters are misrepresenting the terms used within section 111(h)(3) of the CAA and NSPS OOOOa. The commenters state that an approved AMEL would apply to a source category. The source category for which NSPS OOOOa sets standards of performance is the crude oil and natural gas production source category. This category is defined in 40 CFR 60.5430a as "(1) crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station." Within this source category, the EPA has set standards of performance for individual affected facilities. These affected facilities are the only emission sources within the crude oil and natural gas production source category for which the NSPS apply and are defined in 40 CFR 60.5365a.

Specifically, the EPA has defined the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station as individual affected facilities in the rule. The two affected facilities are defined at the individual site level, and not as the collection of fugitive emissions components across multiple sites. Further, the standards that apply to these affected facilities are specific to the individual well site or compressor station, as defined in 40 CFR 60.5365a(i) and (j) and 40 CFR 60.5397a. For example, the collection of fugitive emissions components at an existing well site become subject to the fugitive emissions requirements when (1) a new well is drilled at that well site, (2) an existing well at that well site is hydraulically fractured, or (3) an existing well at that well site is hydraulically refractured. In all three cases, the event that triggers to requirements for an existing well site are based on site-specific changes, and not changes at other nearby sites. Drilling a new well at a well site within the same basin, for instance, does not trigger the fugitive emissions requirements for all well sites located in that basin. However, this is the approach that the commenters state as their preference when demonstrating that an AMEL is equivalent.

When establishing the requirements for the collection of fugitive emissions components, the EPA limited the applicability to individual well sites or compressor stations. The work practice standards that were set in accordance with section 111(h)(1) of the CAA were established for the collection of fugitive emissions components at an individual well site or compressor station. Therefore, the EPA contends that any determination of equivalent emission reductions through an AMEL under section 111(h)(3) of the CAA must be determined at the same affected facility level (i.e., collection of fugitive emissions components at a well site or at a compressor station) as the original work practice standards that are being compared to the alternative.

2. Incorporation of State Fugitive Emissions Programs

EPA received comments related to the alternative fugitive emissions standards on several topics. The comments received by EPA that resulted in significant rule changes are discussed in section V.C.2 of this preamble, along with our response and rationale for the changes. Specifically, these topics were related to whether the state regulations/requirements determined to be alternative fugitive standards to NSPS OOOOa fugitive requirements will provide adequate coverage of the emission sources in the state and the potential for duplicative reporting and recordkeeping requirements. Further details on comments related to these topics are provided below, along with other significant comments and the EPA's response. Other comments, and more detailed comments covering the topics discussed in this preamble, related to the incorporation of state fugitive monitoring programs can be found in the Response to Comment document available in the docket, along with EPA's responses.

Comment: Two commenters stated that the equivalency determinations used to establish an AMEL determination must be quantitative. The commenters indicated that the Agency's analysis evaluated whether a state has regulations that are similar to the EPA's regulations, rather than whether the emissions reductions achieved by those regulations are quantitatively equivalent. One of the commenters stated that the EPA's qualitative comparison is legally insufficient because it does not meet the statutory requirement that an applicant "establish" that the AMEL "will achieve" reductions in emissions "at least equivalent to" the reduction achieved under the federal standards.52 This commenter stated that without a quantitative comparison, it is impossible to determine whether an AMEL will achieve at least an equivalent reduction in pollutant emissions. The commenter further notes that past AMEL approvals under this provision were based on detailed quantitative determinations for each facility to determine the exact emissions levels that would be achievable at that facility, and then those levels were compared to the emissions levels achievable under the present NSPS. The commenter stated that the EPA's policy changes in how equivalency is determined are inconsistent with the requirements of section 111(h) of the CAA and also states that the EPA's approach of "combining . . . aspects of the state requirements to formulate alternatives,"53 to determine equivalency is not a permissible or reasonable approach. The commenter noted that while some aspects of a state-level program may be more protective than the corresponding federal requirements, others may not be, and the commenter states that qualitative comparisons cannot determine the net effects of program elements that point in opposite directions.

Response: The EPA agrees that in some instances when the EPA is evaluating an alternative it would be preferable to use a quantitative analysis, but do not agree that such analysis is necessary or prudent in this instance for determining the equivalency of fugitive emissions requirements in state regulations. The CAA does not require the EPA to conduct a quantitative analysis to evaluate an alternative work practice standard or to determine whether that alternative is equivalent to the underlying work practice standard. Work practice standards under section 111(h)(1) of the CAA are set when "it is not feasible to prescribe or enforce a standard of performance." Section 111(h)(2) of the CAA further defines that the phrase not feasible to prescribe or enforce a standard of performance "means any situation in which the Administrator determines that (A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant..., or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations." Fugitive emissions are not quantified within the rule, and the technologies used to detect fugitive emissions do not quantify the actual emissions that are detected and then remediated through repair. Further, even if direct quantification were possible through the currently approved technologies, those quantified emissions would only represent the fugitive emissions detected on that specific day and would not offer information related to how long those emissions were present prior to detection, or account for any emissions that occur between monitoring surveys. Due to the fact-specific circumstances of the work practice standard in the existing rule, it is not practical for the EPA to conduct an accurate and meaningful quantitative analysis of the proposed alternatives. It is also not necessary for the EPA to conduct a quantitative analysis. Therefore, the most practical way to evaluate the equivalence of a fugitive emissions monitoring and repair program is through the site-specific qualitative comparison that we used. It is the EPA's determination that the analysis, which evaluates the universe of components monitored, the frequency of monitoring, the detection instrument, the threshold that triggers repairs, and the repair deadline, is sufficient and appropriate for demonstrating that the six programs identified as alternative fugitive standards are equivalent to the fugitive emissions requirements of NSPS OOOOa. Therefore, we have not conducted a quantitative analysis of the individual state programs that are finalized in this action as alternative standards.

Comment: One commenter performed their own quantitative assessment of the state programs that the EPA proposed as equivalent to NSPS OOOOa with both the October 15, 2018, proposal and the 2016 NSPS OOOOa. From this analysis, the commenter stated that it found differences in the applicability thresholds for several of the state programs, which results in the state programs (combined) covering only 34% of the total wells that would be covered by the October 15, 2018, proposal or the 2016 NSPS OOOOa in these states. The commenter also stated that state programs vary in stringency and may not reduce emissions to the same level as the EPA standards, such as the Ohio and Texas provisions that allow for inspection frequency to decrease based on the percentage of components leaking. The commenter asserted that their assessment demonstrates that both the Ohio and Texas programs reduce emissions to a lesser extent than the October 15, 2018, proposal, while California and Colorado meet the emission reduction levels accomplished by the October 15, 2018, proposal. Overall, the commenter says that the state programs will achieve a reduction of methane emissions that is 36% less than the reduction that would be achieved by the amendments proposed on October 15, 2018. When compared to the original 2016 NSPS OOOOa requirements, the commenter said that the state programs result in 58% less emissions reductions. The commenter remarked that these findings demonstrate that these state programs are not equivalent to either the October 15, 2018, proposal or the 2016 NSPS OOOOa. Another commenter also remarked that California Air Resources Board has performed a preliminary assessment of state programs against the 2016 NSPS OOOOa and found that only the California, Colorado, Pennsylvania, Utah, and Texas (within narrow parameters) are likely to be equivalent.

Response: The EPA reviewed the analysis provided by the commenter but note that this analysis appears to not consider specific limitations on the use of the alternative fugitive standards. Specifically, the commenter states only 34% of the wells covered by the fugitive emissions requirements in NSPS OOOOa, that are also located in one of the six states with alternative fugitive standards, would actually be subject to those alternative fugitive standards. This is not correct. The assumption by the commenter then is that the alternative standard is deficient because not all of the sites will be required to monitor, thus reduce fugitive emissions.

Using Texas as an example, the commenters stated that only 5% of the sites that are subject to NSPS OOOOa would also have monitoring requirements under the alternative fugitive standards for well sites located in Texas. While the EPA agrees that this percentage of sites in Texas affected by the Texas standards may be accurate, 100% of those sites would be able to avail themselves to the alternative fugitive standards based on the requirements in Texas. That is, if the well site is subject to the standards of the specified requirements in Texas, then that well site may opt to comply with those state-level standards as an alternative to certain federal fugitive emissions requirements in NSPS OOOOa. However, if a well site in Texas is not subject to the state-level monitoring requirements due to a provision such as an applicability threshold included in the state standards and that well site is subject to the NSPS, then the alternative standard would not apply to that site, and monitoring would be required through the requirements in NSPS OOOOa. Put another way, the alternatives included in this final rule do not alter the applicability criteria of the NSPS for any sites. If a well site in Texas was required to comply with the NSPS before the alternative was approved, then that site is still required to comply with the NSPS, but the final rule affords certain sites in Texas an alternative way to demonstrate that compliance if they so choose. Regardless of whether the site complies with the fugitive emissions requirements in NSPS OOOOa, or the alternative fugitive standards for their state, they must conduct the specific monitoring and repair.

Comment: Several commenters asserted that the EPA should recognize the approved state programs as wholly equivalent to the fugitive emissions requirements in the NSPS and fully delegate the implementation of those fugitive emissions requirements to those states, including the states' recordkeeping and reporting requirements. The commenters noted that the EPA is requiring operators to use the fugitive emission component definition from the 2016 NSPS OOOOa and the 2016 NSPS OOOOa reporting and monitoring plan.

Two of the commenters observed that they are required to comply with both the state permit requirements and federal fugitive emissions programs concurrently. The commenters state that complying with two different recordkeeping and reporting schemes for the same site is very burdensome with no added benefit for the environment. The commenters also stated that requiring the federal reporting and monitoring plan defeats the purpose and any benefit from the EPA approving state programs and suggest that if a state program is not adequate in the EPA's opinion, then the EPA should address the issue with the individual state, so it can be approved in whole. Commenters added that as an alternative, the EPA could require that the fugitive emissions component definition from NSPS OOOOa be used when following an AMEL program, even if the state program definitions differ, but the EPA should not require a duplicative administrative burden.

Further, the commenters stated that CAA Section 111 fits squarely within the cooperative federalism tradition, with Section 111(c) expressly calling on states to develop "a procedure for implementing and enforcing standards of performance for new sources" and calling on the Administrator to delegate "any authority he has ... to implement and enforce such standards."54 Two commenters noted that the EPA did not evaluate the equivalency of state reporting requirements or monitoring plans and, thus, did not propose any alternative standards for these aspects of the NSPS OOOOa fugitive emissions requirements. These commenters state that the exclusion of state reporting and monitoring plan requirements from the EPA's equivalency evaluation leaves the regulated community in certain states subject to potentially duplicative regulation.

Response: After considering the comments provided, the EPA reviewed the recordkeeping and reporting requirements for each of the 6 states that were proposed for alternative fugitive standards in the October 15, 2018, proposal (California, Colorado, Ohio, Pennsylvania, Texas, and Utah). For California, Ohio, and Pennsylvania, the EPA was able to identify site-specific reporting requirements in the state reports which, while not identical to the reporting for NSPS OOOOa, were determined to be appropriate to demonstrate compliance with the alternative fugitive standards for those states. Therefore, in this final rule, we are allowing well sites and compressor stations located in California, Ohio, and Pennsylvania that adopt the alternative fugitive standards to submit a copy of the report that is submitted to their state instead of reporting to the EPA in accordance with 40 CFR 60.5420a(b)(7)(i) and (ii). This report must be submitted in the format in which it was submitted to the state, as an attachment to the annual report for NSPS OOOOa.

In reviewing the reporting requirements for Colorado, we noted that the report is a fillable form to the state that summarizes all monitoring events for that year at the company-level. Therefore, no site-specific information is available. We then reviewed the recordkeeping forms for Colorado to identify what information is required for the individual sites and compared that information to the required annual report for NSPS OOOOa. We identified two items that were not already included in the record: (1) weather conditions (i.e., ambient temperature, sky conditions, and maximum wind speed at the time of the survey) and (2) deviations from certain requirements in the monitoring plan. Given that the monitoring plan is still required for sites that adopt the alternative fugitive standards, the only additional records that we could identify for well sites and compressor stations located in Colorado are the weather conditions. It is our determination that the Colorado program is equivalent or better than the fugitive emissions requirements in NSPS OOOOa, but that state-level reports in Colorado are insufficient to demonstrate compliance for individual sites. Therefore, we are still requiring that well sites and compressor stations located in Colorado that adopt the alternative fugitive standard must report the information required in NSPS OOOOa. It appears that sites located in the state are already required by the state to keep records that facilitate the reporting required by the NSPS. The additional record for weather conditions is a minimal burden.

Our review of Texas reporting requirements found that sites only report information when fugitive emissions are found. While this may be appropriate for demonstrating compliance to the state, it is not adequate information for the EPA to ensure compliance with the alternative fugitive standards for well sites and compressor stations located in Texas. Similar to Colorado, we examined the recordkeeping requirements and found that sites located in the state are already required by the state to keep records that facilitate the reporting required by the NSPS. Therefore, we are requiring that well sites and compressor stations located in Texas that adopt the alternative fugitive standard must report the information required in NSPS OOOOa.

Finally, the requirements in Utah do not include reporting. Similar to Colorado and Texas, we reviewed the recordkeeping requirements. For Utah, sites must keep records of the monitoring plan and the monitoring surveys. We found these records are similar to the information that is required in the NSPS OOOOa report for fugitive emissions components. However, like Colorado, we were unable to determine if weather conditions are recorded for the state required surveys in the state of Utah. As stated above for Colorado, the additional record for these weather conditions presents a minimal burden, and the other information required by the NSPS OOOOa report is already available in the state required records that are maintained for compliance with Utah's program. Therefore, we are requiring that well sites located in Utah that adopt the alternative fugitive standard must report the information required in NSPS OOOOa.

VII. Impacts of These Final Amendments

A. What are the air impacts?

The only expected impacts on methane, VOC, and HAP emissions from this reconsideration are likely to be from reducing the monitoring frequency for affected compressor stations on the Alaskan North Slope. However, EPA does not have information that enables the projection of emissions changes that may result from reducing the frequency of fugitive emissions monitoring at these Alaskan sites. All other finalized changes to the NSPS OOOOa are not expected to lead to changes in emissions. As a result, air impacts are expected to be minimal.

B. What are the energy impacts?

Energy impacts in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussion in the economic impacts section. There would be minimal change in emissions control energy requirements resulting from the provisions in this action. Additionally, this final action continues to encourage the use of emission controls that recover hydrocarbon products that can be used on-site as fuel or reprocessed within the production process for sale.

C. What are the compliance cost savings?

For this action, the EPA estimated the change in compliance costs projected to occur due to the implementation of the reconsideration for the analysis years of 2019 through 2025. We estimate impacts beginning in 2019 to reflect the year implementation of this reconsideration will begin. We estimate impacts through 2025 to illustrate the continued compound effect of this rule over a longer period. We do not estimate impacts after 2025 for reasons including limited information, as explained in the RIA. The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2016 to 2024 that are also assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

Because of reductions in reporting and recordkeeping requirements and the flexibility to use an in-house engineer for CVS certifications, the finalized changes are expected to result in cost savings for the affected firms. The PV of these cost savings, discounted at a 7 percent rate, is estimated to be about $189 million dollars, with an EAV of about $33 million (Table 1). Under a 3 percent discount rate, the PV of cost savings is $240 million, with an EAV of $37 million (Table 1).

D. What are the economic and employment impacts?

In the RIA accompanying the 2016 NSPS OOOOa rulemaking, the EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the 2016 NSPS OOOOa on the

United States energy system. The NEMS is a publicly-available model of the United States energy economy developed and maintained by the EIA and is used to produce the AEO, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA estimated small impacts of that rule over the 2020 to 2025 period relative to the baseline for that rule. This reconsideration is estimated to result in a decrease in total compliance costs, with the reduction in costs affecting a subset of the affected entities under NSPS OOOOa. Therefore, the EPA expects that this deregulatory action, if finalized, would reduce the impacts estimated for the final NSPS in the 2016 RIA.55

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, "our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science." (Executive Order 13563, 2011.) While a standalone analysis of employment impacts is not included in a standard benefit-cost analysis, such an analysis is of particular concern in the current economic climate given continued interest in the employment impact of regulations such as this reconsideration.

The EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, control activities, and labor associated with new reporting and recordkeeping requirements in the 2016 NSPS OOOOa RIA. For this reconsideration, the EPA expects there will be slight reductions in the labor required for compliance-related activities associated with the 2016 NSPS OOOOa requirements relating to fugitive emissions and inspections of closed vent systems. However, due to uncertainties associated with how the reconsideration will influence the portfolio of activities associated with fugitive emissions-related requirements, the EPA is unable to provide quantitative estimates of compliance-related labor changes.

E. What are the forgone benefits?

As there are not quantified emissions impacts from the finalized option, the finalized changes to NSPS OOOOa are not expected to result in monetized disbenefits. The only expected impacts on VOC, methane, and HAP emissions from this reconsideration are likely to be from reducing the monitoring frequency for affected compressor stations on the Alaskan North Slope. However, EPA does not have information that enables the projection of forgone benefits that may result from reducing the frequency of fugitive emision monitoring at these Alaskan sites.

VIII. Statutory and Executive Orders Reviews

Additional information about these statutes and Executive Orders can be found at http://www2.epa.gov/laws-regulations/laws-and-executive-orders.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This RIA is available in the docket. The RIA describes in detail the basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 4 shows the present value and equivalent annualized value of the projected cost and benefits for the final rule over the 2019 to 2025 period, discounted back to 2016 using a discount rate of 7 percent.

When discussing net benefits, we modify the relevant terminology to be more consistent with traditional net benefits analysis. In the following table, we refer to the cost savings as the "benefits" of this action and the forgone benefits as the as the "costs" of this action. The net benefits are the benefits (cost savings) minus the costs (forgone benefits).

Table 4. Summary of the Present Value and Equivalent Annualized Value of the Monetized Benefits, Costs, and Net Benefits of the Final Oil and Natural Gas Reconsideration from 2019 through 2025 (Millions of 2016$)

Present Value

Equivalent Annualized Value

Benefits (Total Cost Savings)

$189 million

$33 million

Costs (Forgone Benefits)

$0 million

$0 million

Net Benefits

$189 million

$33 million

Estimates may not sum due to independent rounding

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is expected to be an Executive Order 13771 deregulatory action. Details on the estimated cost savings of this final rule can be found in the EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICE number 2523.03. This final reconsideration revises the information collection activities of the 2016 NSPS OOOOa. You can find a copy of the 2016 ICR in the 2016 NSPS OOOOa docket (EPA-HQ-OAR-2010-0505-7626). You can find a copy of the revised ICR in the docket for this rule (EPA-HQ-OAR-2017-0483), and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The changes to the 2016 NSPS OOOOa information collection activities will reduce the burden on the regulated industry associated with reporting and recordkeeping requirements. Final amendments to the reporting and recordkeeping requirements are presented in section 60.5420a. Other information collection activity reductions will result from amendments that streamline and align monitoring requirements (and associated recordkeeping) in the rule.

Comments were received on the October 15, 2018, proposed reconsideration indicating that the recordkeeping and reporting burden for the 2016 NSPS OOOOa was significantly underestimated. In particular, the commenters point to the estimated burden associated with the fugitive emissions requirements. As a result of these comments, the EPA reexamined the analysis for the 2016 NSPS OOOOa reporting and recordkeeping burden and made adjustments where warranted. This resulted in an updated and more accurate assessment of the reporting and recordkeeping burden for NSPS OOOOa as finalized in 2016. The updated 2016 NSPS OOOOa reporting and recordkeeping burden was estimated at a 3-yr annual average of 433,486 hours and $66,079,412 (2016$) over the three-year period. This represents the "baseline" from which changes made in these final amendments can be compared.

The estimated average annual burden (averaged over the first 3 years after the effective date of the revised standards) for the recordkeeping and reporting requirements associated with the amendments to NSPS OOOOa for the estimated 498 owners and operators subject to the rule is 244,103 labor hours, with an average annual cost of $49,817,149 (2016$) over the three-year period. The information collection activities associated with the amendments will result in an estimated average annual burden reduction of 25 percent on a cost basis compared to the updated 2016 NSPS OOOOa burden discussed above (2016$).

Respondents/affected entities: Owners or operators of onshore oil and natural gas affected facilities

Respondent's obligation to respond: Mandatory

Estimated number of respondents: 498

Frequency of response: Annually or semiannually, depending on the requirement.

Total estimated burden: 244,103 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $49,817,149 (per year), includes $1,622,006 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the Federal Register and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. This is a deregulatory action, and the burden on all entities affected by this final rule, including small entities, is reduced compared to the 2016 NSPS OOOOa. See the RIA for details. We have therefore concluded that this action will relieve regulatory burden for all directly regulated small entities.

E. Unfunded Mandates Reform Act of 1995 (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531-1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local or tribal governments or the private sector.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

H. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. As described elsewhere in this preamble and in the RIA associated with this action, the only expected impacts on methane, VOC, and HAP emissions from this reconsideration are likely to be from reducing the monitoring frequency for affected compressor stations on the Alaskan North Slope. However, EPA does not have information that enables the projection of emissions changes that may result from reducing the frequency of fugitive emissions monitoring at these Alaskan sites. All other finalized changes to the NSPS OOOOa are not expected to lead to changes in emissions. As a result, air impacts are expected to be minimal.

I. Executive Order 13211: Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use

This action is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. In the RIA accompanying the 2016 NSPS OOOOa rulemaking, the EPA used the NEMS to estimate the impacts of the 2016 NSPS OOOOa on the United States energy system. The EPA estimated small impacts of that rule over the 2020 to 2025 period relative to the baseline for that rule. This reconsideration is estimated to result in a decrease in total compliance costs, with the reduction in costs affecting a subset of the affected entities under NSPS OOOOa. Therefore, the EPA expects that this deregulatory action, if finalized, would reduce the impacts estimated for the final NSPS in the 2016 RIA and, as such, is not a significant energy action.

J. National Technology Transfer and Advancement Act (NTTAA)

This action involves technical standards.56 Therefore, the EPA conducted searches for the Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 18, 21, 22, and 25A of 40 CFR part 60 Appendix A. No applicable voluntary consensus standards were identified for EPA Methods 1A, 2A, 2D, 21, and 22 and none were brought to its attention in comments. All potential standards were reviewed to determine the practicality of the voluntary consensus standards (VCS) for this rule.

Two VCS were identified as an acceptable alternative to the EPA test methods for the purpose of this rule. First, ANSI/ASME PTC 19-10-1981, Flue and Exhaust Gas Analyses (Part 10) was identified to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A, and 16A manual portions only and not the instrumental portion. This standard includes manual and instructional methods of analysis for carbon dioxide, carbon monoxide, hydrogen sulfide, nitrogen oxides, oxygen, and sulfur dioxide. Second, ASTM D6420-99 (2010), "Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry," is an acceptable alternative to EPA Method 18 with the following caveats; only use when the target compounds are all known and the target compounds are all listed in ASTM D6420 as measurable. ASTM D6420 should never be specified as a total VOC Method. (ASTM D6420-99 (2010) is not incorporated by reference in 40 CFR part 60.) The search identified 19 VCS that were potentially applicable for this rule in lieu of the EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data, and other important technical and policy considerations. For additional information, please see the memorandum Voluntary Consensus Standard Results for Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration, located at Docket ID No. EPA-HQ-OAR-2017-0483.

K. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994).

As described elsewhere in this preamble and in the RIA associated with this action, the only expected impacts on methane, VOC, and HAP emissions from this reconsideration are likely to be from reducing the monitoring frequency for affected compressor stations on the Alaskan North Slope. However, EPA does not have information that enables the projection of emissions changes that may result from reducing the frequency of fugitive emissions monitoring at these Alaskan sites. All other finalized changes to the NSPS OOOOa are not expected to lead to changes in emissions. As a result, air impacts are expected to be minimal and not likely to have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping.

Dated: ______________________________.

____

Andrew R. Wheeler,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is proposed to be amended as follows:

PART 60-- STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, et seq.

Subpart OOOOa-Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

1 Docket ID No. EPA-HQ-OAR-2010-0505.

2 Copies of the petitions are provided in Docket ID No. EPA-HQ-OAR-2017-0483.

3 See Docket ID No. EPA-HQ-OAR-2010-0505-7730.

4 82 FR 25730.

5 See Docket ID No. EPA-HQ-OAR-2010-0505-7632, Chapter 4, page 4-319.

6 See RTC document and TSD in Docket ID No. EPA-HQ-OAR-2017-0483.

7 Replacing an old storage vessel in the group with a new storage vessel would not increase emissions and therefore, is not considered a modification.

8 The rule allows the use of Method 21 as an alternative to OGI but did not conclude Method 21 was BSER because OGI was found to be more cost-effective. See 81 FR 35856.

9 See TSD at Docket ID No. EPA-HQ-OAR-2017-0483.

10 Placeholder for reference to API cost data letter.

11 Placeholder for reference to API cost data letter.

12 See TSD at Docket ID No. EPA-HQ-OAR-2017-0483.

13 Placeholder for API cost data and GPA meeting memo.

14 See Docket ID No. EPA-HQ-OAR-2017-0483-0757.

15 See TSD for additional information on the estimated cost burden at the individual site level at Docket ID No. EPA-HQ-OAR-2017-0483.

16 Canadian Association of Petroleum Producers, "Update of Fugitive Equipment Leak Emission Factors," prepared for Canadian Association of Petroleum Producers by Clearstone Engineering, Ltd., February 2014.

17 See memorandum EPA Analysis of Fugitive Emissions Data Provided by INGAA located at Docket ID No. EPA-HQ-OAR-2017-0483-0060. August 21, 2018.

18 Placeholder for INGAA comments and supplemental memos.

19 Canadian Association of Petroleum Producers, "A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC), and Hydrogen Sulphide (H_2S) Emissions by the Upstream Oil and Gas Industry,"September 2004.

20 Canadian Association of Petroleum Producers, "Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities," January 2007.

21 Canadian Association of Petroleum Producers, "Update of Fugitive Equipment Leak Emission Factors," prepared for Canadian Association of Petroleum Producers by Clearstone Engineering, Ltd., February 2014.

22 See Docket ID No. EPA-HQ-OAR-2017-0483-2041.

23 See Appendix D to Docket ID No. EPA-HQ-OAR-2017-0483-2041.

24 See US EPA, "1995 Protocol for Equipment Leak Emission Estimates Emission Standards" located at Docket ID No. EPA-HQ-OAR-2017-0483-0002.

25 See TSD located at Docket ID No. EPA-HQ-OAR-2017-0483.

26 See Docket ID Nos. EPA-HQ-OAR-2017-0483-0801 and EPA-HQ-OAR-2017-0483-2041.

27 See Docket ID No. EPA-HQ-OAR-2017-0483-1261.

28 See US EPA, "1995 Protocol for Equipment Leak Emission Estimates Emission Standards" located at Docket ID No. EPA-HQ-OAR-2017-0483-0002.

29 Memorandum. Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR Part 60, Subpart OOOOa Related to Model Plant Fugitive Emissions. DATE

30 Arvind P. Ravikumar and Adam R. Brandt, "Designing better methane mitigation policies: the challenge of distributed small sources in the natural gas sector," Environmental Research Letters, 12, 2007.

31 It is important to note the FW Study collected information on emissions prior to the promulgation of the fugitive emissions requirements in NSPS OOOOa.

32 Memorandum. Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR Part 60, Subpart OOOOa Related to Model Plant Fugitive Emissions. DATE

33 Colorado Department of Public Health and Environment, "Regulatory Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulation Numbers 3, 6, and 7 (5 CCR 1001-5, 5 CCR 1001-8, and CCR 1001-9), February 2014.

34 See Docket ID No. EPA-HQ-OAR-2017-0483-1006.

35 See Docket ID No. EPA-HQ-OAR-2017-0483-1261.

36 See Docket ID No. EPA-HQ-OAR-2017-0483-1002.

37 Gas Research Institute (GRI)/U.S. EPA. Research and Development, Methane Emissions from the Natural Gas

Industry, Volume 8: Equipment Leaks. June 1996 (EPA-600/R-96-080h).

38 See 81 FR 56616. Under the single pollutant approach, we assign all costs to the reduction of one pollutant and zero costs for all other pollutants simultaneously reduced. Under the multipollutant approach, we allocate the annualized costs across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. For purposes of the multipollutant approach, we assume that emissions of methane and VOC are equally controlled, therefore half of the cost is apportioned to the methane emission reductions and half of the cost is apportioned to VOC emission reductions. In this evaluation, we examined both approaches across the range of identified monitoring frequencies, annual, semiannual, and quarterly.

39 See TSD for additional analysis and cost information, located at Docket ID No. EPA-HQ-OAR-2017-0483.

40 See TSD for additional analysis and cost information, located at Docket ID No. EPA-HQ-OAR-2017-0483.

41 See TSD for additional analysis and cost information, located at Docket ID No. EPA-HQ-OAR-2017-0483.

42 See https://energy.colostate.edu/metec for more information on the METEC facility.

43 See memorandum Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa, located at Docket ID No. EPA-HQ-OAR-2017-0483. DATE.

44 See memorandum Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Final Standards at 40 CFR part 60, subpart OOOOa, located at Docket ID No. EPA-HQ-OAR-2017-0483. DATE.

45 See Docket ID No. EPA-HQ-OAR-2017-0483-2041.

46 See Chapter 6 of the RTC located at Docket ID No. EPA-HQ-OAR-2017-0483.

47 Placeholder for meeting memos.

48 See Chapter 4 of the RTC for the 2016 NSPS OOOOa located at Docket ID No. EPA-HQ-OAR-2010-0505-7632.

49 Memorandum. Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR Part 60, Subpart OOOOa Related to Model Plant Fugitive Emissions. DATE

50 https://www.netl.doe.gov/node/5775.

51 See 40 CFR 60.18(g), (h), and (i).

52 See CAA Section 111(h)(3).

53 See 83 FR 52081.

54 See CAA section 111(c)(1).

55 See Docket ID No. EPA-HQ-OAR-2010-0505-7630.

56 These proposed technical standards are the same as those previously finalized at 40 CFR part 60, subpart OOOOa (81 FR 35824). 2016 NSPS OOOOa also previously incorporated by reference 10 technical standards. The incorporation by reference remains unchanged in this proposed action. See Docket ID Nos. EPA-HQ-OAR-2010-0505-7657 and EPA-HQ-OAR-2010-0505-7658.

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